CALIFORNIA ENERGY COMMISSION

SCENARIO ANALYSES OF CALIFORNIA'S ELECTRICITY SYSTEM: PRELIMINARY RESULTS FOR THE *2007 INTEGRATED ENERGY POLICY REPORT*

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ABSTRACT

In this 2007 report, California Energy Commission staff uses a scenario analysis approach to examine the implications of resource plans featuring very high penetrations of energy efficiency measures and renewable energy generation (both rooftop solar photo-voltaic and supply-side generating technologies) in California and the Western Interconnection. Among the variables of interest are generation mix to support load, greenhouse gas emissions, system and production costs of generation, fuel consumed in power generation, criteria pollutant emissions, and transmission additions needed in each scenario. The study does not attempt to identify the optimal penetration of preferred resources (efficiency and renewables), but rather, explores how combinations of increases in penetrations in California and the West affect greenhouse gas emissions, resource requirements, transmission requirements, and cost in those geographic areas.

Staff examined more than 50 cases for the entire Western Interconnection using nine thematic scenarios with sensitivities for high and low fuel prices, plus high and low hydro-electric generation. This range of thematic scenarios allows preferred resource plans to be compared to what might be expected from resource plans with more conventional resources. The preliminary findings of this study include:

- Increased penetration of preferred resources reduces greenhouse gas emissions significantly even when dispatchable resources to assure reliability are taken into account,
- Reductions in fossil generation that result from increased penetrations of efficiency and renewables are attributable to the displacement of production from some existing generation facilities as well as the deferral or elimination of some anticipated fossil facilities,
- Natural gas generation is found to be the swing fuel in nearly all cases, with coal-based electric generation little affected by levels of energy efficiency and renewables that were investigated,
- Increased penetration of preferred resources outside California increases imports into California, and
- Assuming a fixed set of technology characteristics and costs, increased penetrations of energy efficiency and renewables may increase total system costs as the capital cost additions of these resource types outweigh the production costs savings.

KEYWORDS: resource plans, energy efficiency, renewable generation, solar photo-voltaic, greenhouse gases, power generation, scenario analysis, generation costs, production costs, transmission, Western Interconnection, sensitivity assessment.

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EXECUTIVE SUMMARY

The purpose of this study is to examine the implications of resource plans featuring very high penetrations of preferred resources (energy efficiency measures and renewable energy generation) in California and the Western Interconnection as defined by the scope of the Western Electricity Coordinating Council. Among the variables of interest is the effect of a reduction in greenhouse gas emissions compared to what might be expected from resource plans with more conventional resources. The greenhouse gas reduction potential demonstrated here is limited to carbon reduction because the greenhouse gas reductions modeled are associated with reductions in fossil based electricity generation. The reductions in fossil generation that accompany increased penetrations of efficiency and renewables are attributable to the displacement of production from some existing generation facilities as well as the deferral or elimination of some anticipated fossil facilities. The study does not attempt to identify the optimal penetration of efficiency and renewables, but rather, explores how combinations of increases in penetrations in California and the West affect greenhouse gas emissions, resource requirements, transmission requirements, and cost in those geographic areas.

The study builds upon previous efforts by the California Energy Commission, the California Public Utilities Commission, the Clean and Diversified Energy Advisory Committee to the Western Governors Association, and others to identify the implications of various strategies to rely more on efficiency and renewables in the electricity sector. Rather than duplicating these efforts, this study attempts to complement those earlier efforts by investigating:

- The interaction between increased penetration of preferred resources and the associated transmission and fossil generation requirements needed to maintain system reliability at an inter-transarea level of analysis;
- The interaction between increased penetrations of preferred resources in California and increased penetrations in the West, especially on the dispatch of fossil power plants;
- The greenhouse gas emission implications of high penetrations of the preferred resource types;
- The effects of the interaction between increasing penetrations of renewables and the natural gas market; and
- The relative cost effects of increasing penetrations of preferred resources in California and the West.

The study investigated the following thematic scenarios using both deterministic production cost modeling as well as sensitivity assessments for some of the variables thought to materially affect the results:

- Case 1 — Current conditions extended into the future.
- Case 1B — Compliance with current requirements.

- Case 2 — High sustained natural gas and coal prices.
- Case 3A — High energy efficiency in California only.
- Case 3B — High energy efficiency throughout the West.
- Case 4A — High renewables in California only.
- Case 4B — High renewables throughout the West.
- Case 5A — High energy efficiency and renewables in California only.
- Case 5B — High energy efficiency and renewables throughout the West.

Figure ES-1 summarizes the relative differences among the nine scenarios in terms of their reliance upon energy efficiency and renewables in California.

Four figures provide an overview of the results for California of these nine thematic cases. Figure ES-2 uses a stacking bar format to describe the resource mix that corresponds to each of the same thematic scenarios for year 2020. The conventional resource scenario on the left has a much larger proportion of generation from natural gas than the scenario furthest to the right, which presumes a large increase in energy efficiency and supply-side renewable generation. An important result of the analysis is the wide difference in level of imports into California across these scenarios. Figure ES-3 illustrates the change in California carbon responsibility for year 2020 among the scenarios assessed. A conventional resource mix on the left has higher carbon emissions than the one on the right, with the largest amount of energy efficiency and renewables across the West. Even though the resource mix of the two rightmost scenarios is quite different between the amounts of natural gas consumed in California versus power imported into California, the level of carbon emission shown on Figure ES-3 is nearly the same. Each of the pairs of cases—3A and 3B, 4A and 4B, and 5A and 5B—show slightly higher total emissions in the "B" version because of higher imports. This study suggests that as long as power plant dispatch decisions continue to follow least-cost principles, the sourcing of California's carbon emissions is substantially affected by the relative resource mix and cost differentials between power plants in California versus those in the "Rest-of-WECC," that is, all of the Western Interconnection other than California.

Figure ES-4 shows the projected change in total, aggregated generation costs for all of California across the nine cases. These results have been assessed presuming that technology cost and performance stay constant through time, except for rooftop solar photo-voltaic that is assumed to decrease by 50 percent. With this caveat, system costs tend to increase as greater proportions of energy efficiency and renewables satisfy electricity requirements. Production costs tend to decrease as energy efficiency and renewables play a larger role. The modeling results clearly reveal a capital cost versus production cost tradeoff. Figure ES-5 shows the projected change in per unit generation costs.

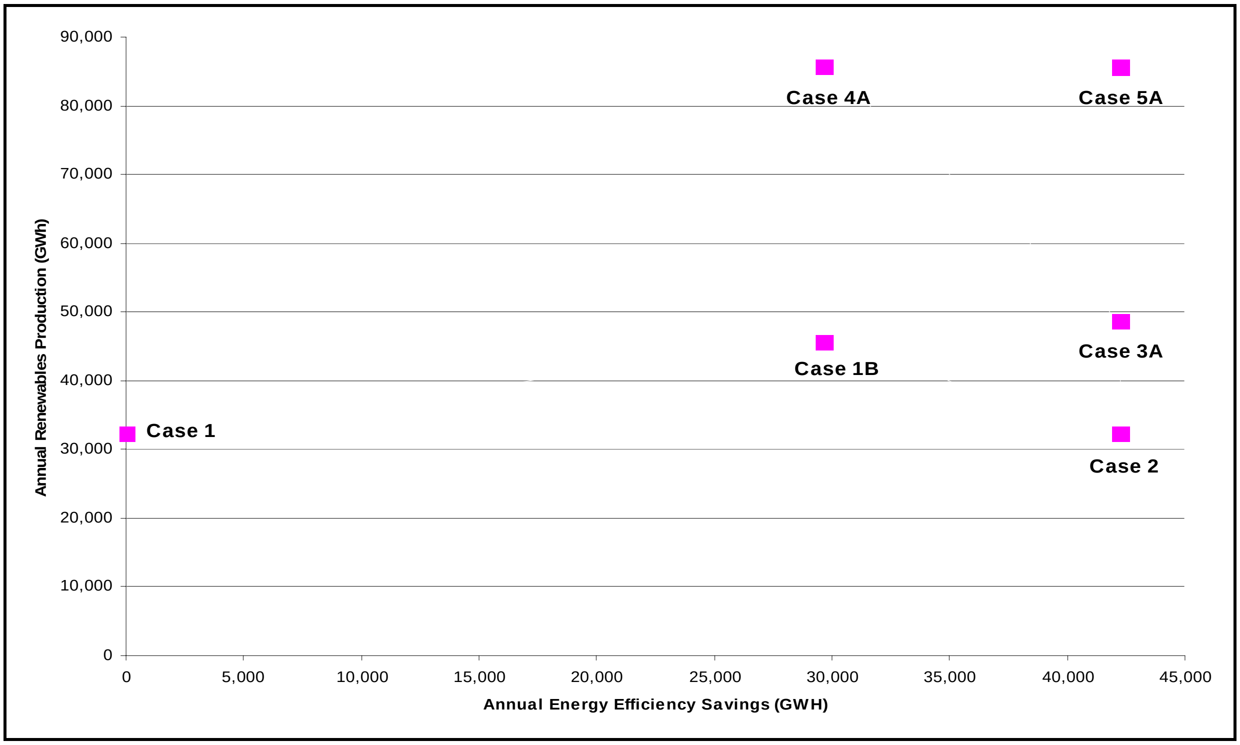
Although the enhancements of this study improve upon weaknesses of previous studies, the results presented should be considered indicative rather than determinative. The study findings are indicative because this study seeks to provide insight on an issue that is laden with scientific, technological, and institutional uncertainties. While the presence of uncertainties should not dissuade policy makers from seeking analytical foundations for their decisions, the presence of uncertainty should motivate them to note the assumptions, evaluate the sensitivity of results to changes in the assumptions, and identify future work to test the sensitivity of the findings to changes in the assumptions. This study has not sought to identify the optimal level of energy efficiency or renewables or the best policy for attaining specific greenhouse gas levels. Such a study would want to consider addressing the data, assumptions, and modeling limitations that will be presented in detail in Chapter 9.

The preliminary findings of this study include the following:

- Increased penetration of preferred resources reduces greenhouse gas emissions significantly, even when dispatchable resources to assure reliability are taken into account;
- Increased penetration of preferred resources outside California increases imports into California as surpluses of cheaper Rest-of-WECC power plants displace more expensive California power plants ; and
- Assuming a fixed set of technology characteristics and costs, increased penetrations of energy efficiency and renewables may increase total system costs as the capital cost additions of these resource types outweigh the production costs savings.

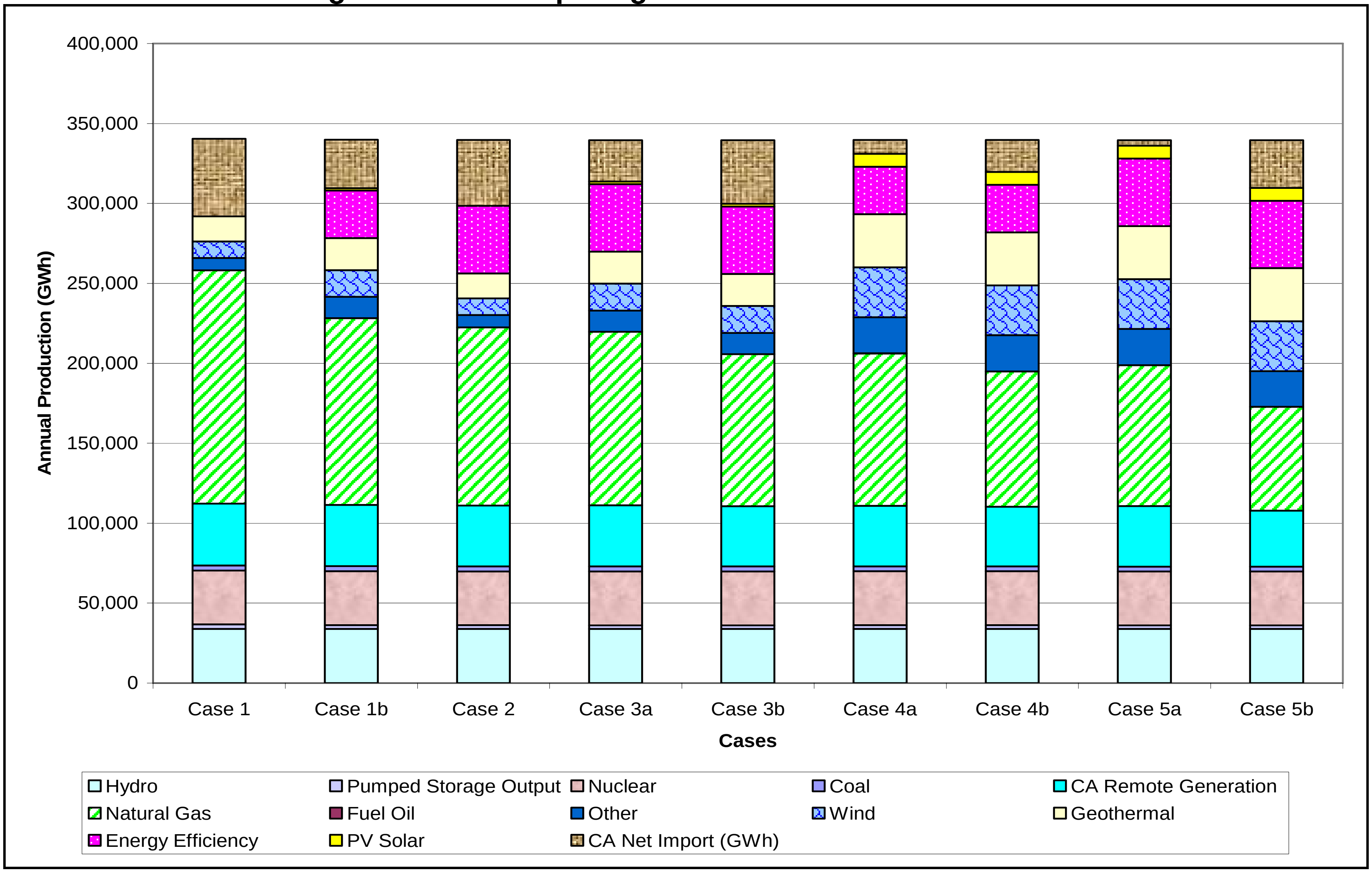
Numerous data and analytic limitations should be considered in interpreting these results. A number of uncertainties could fundamentally affect results that were not explicitly addressed in this study. The effects of these uncertainties on outcome metrics are complex. The magnitude of the effects and the potential for some effects to be mutually reinforcing mean that these uncertainties could substantially affect the results. Further enhancements would be needed to remove or diminish some of the known uncertainties.

Figure ES-1: Preferred Resource Composition of California Thematic Scenarios in 2020



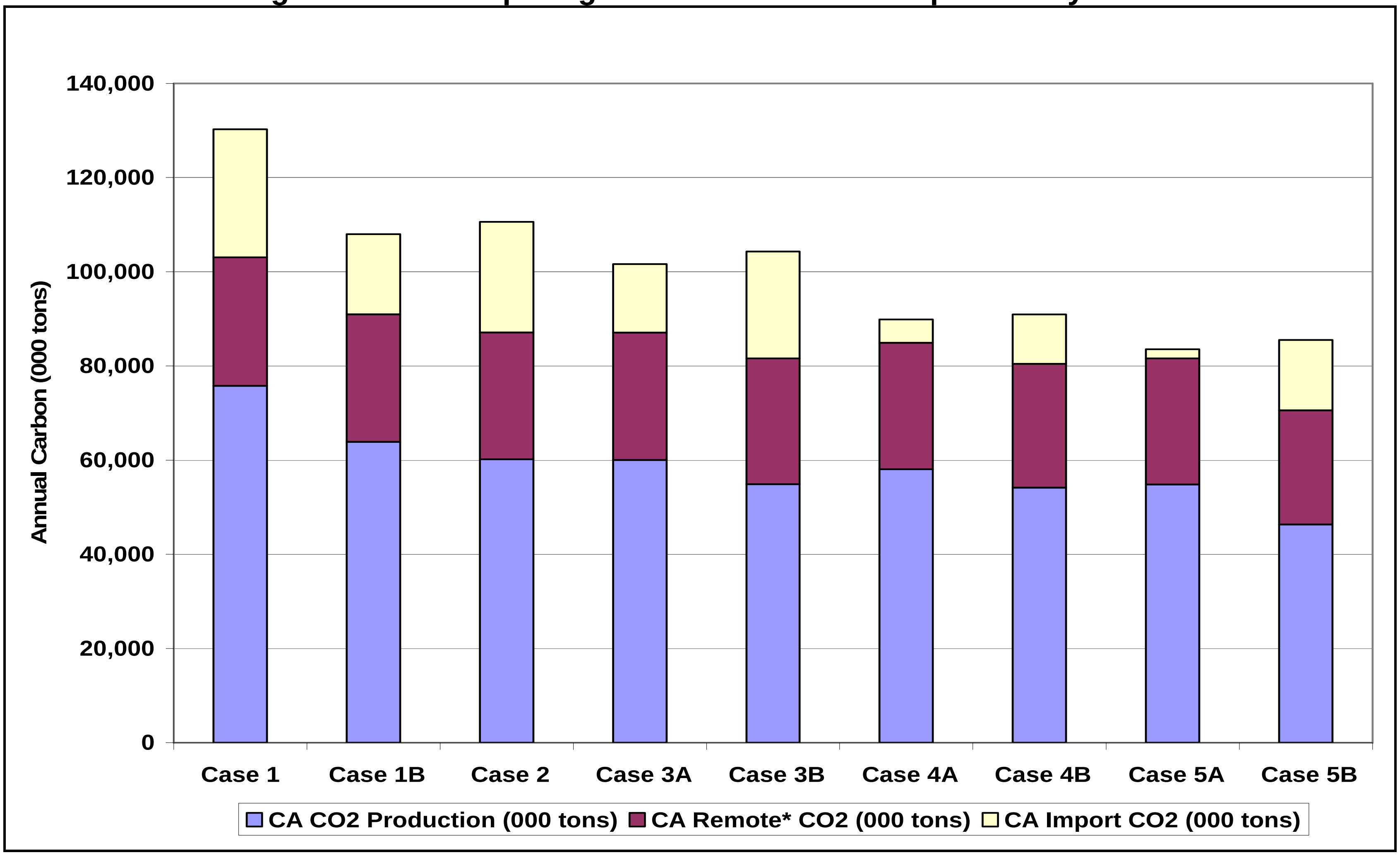
Source: Energy Commission Scenario Project

Figure ES-2: Comparing California Resource Mix in Year 2020



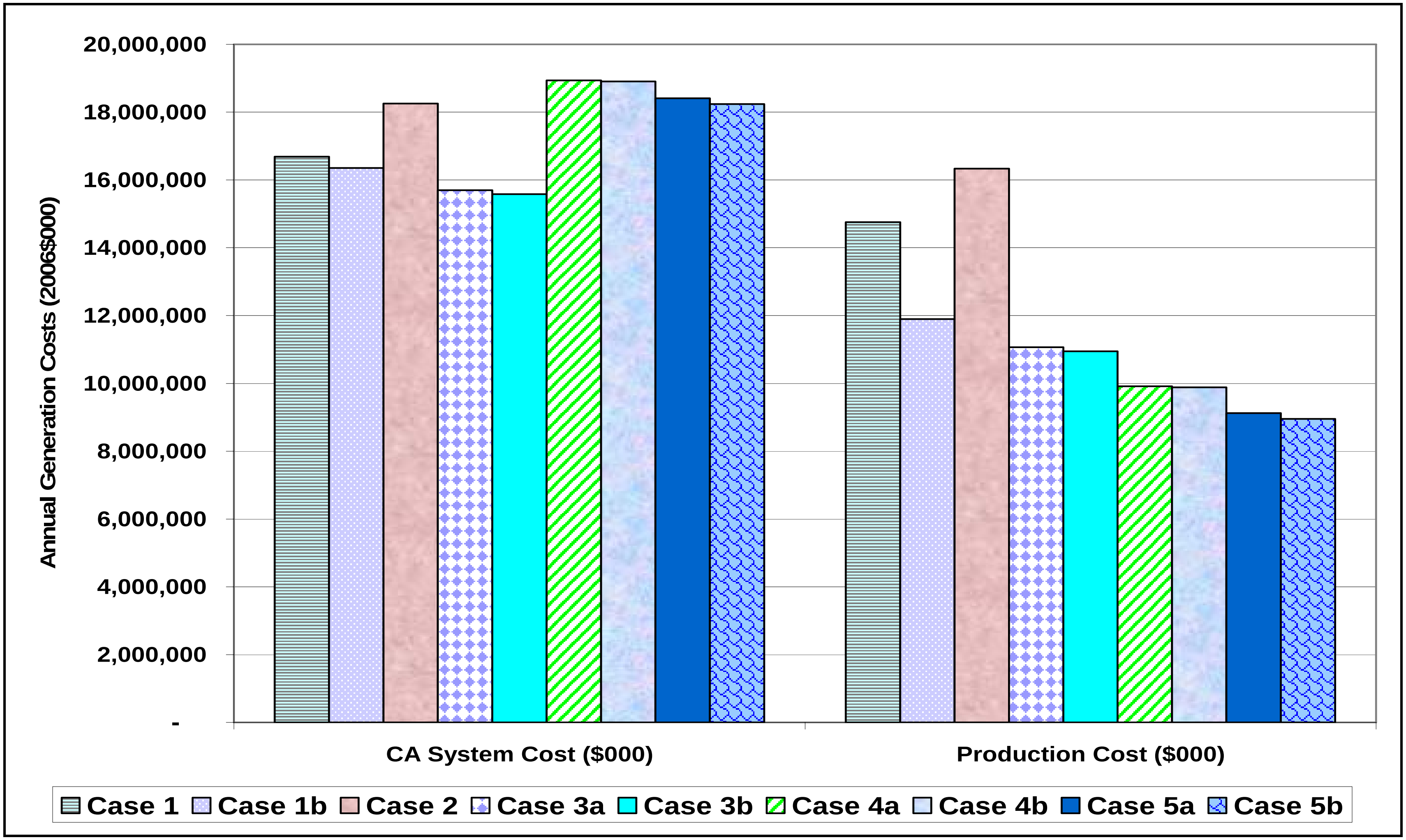
Source: Energy Commission Scenario Project

Figure ES-3: Comparing California Carbon Responsibility in Year 2020



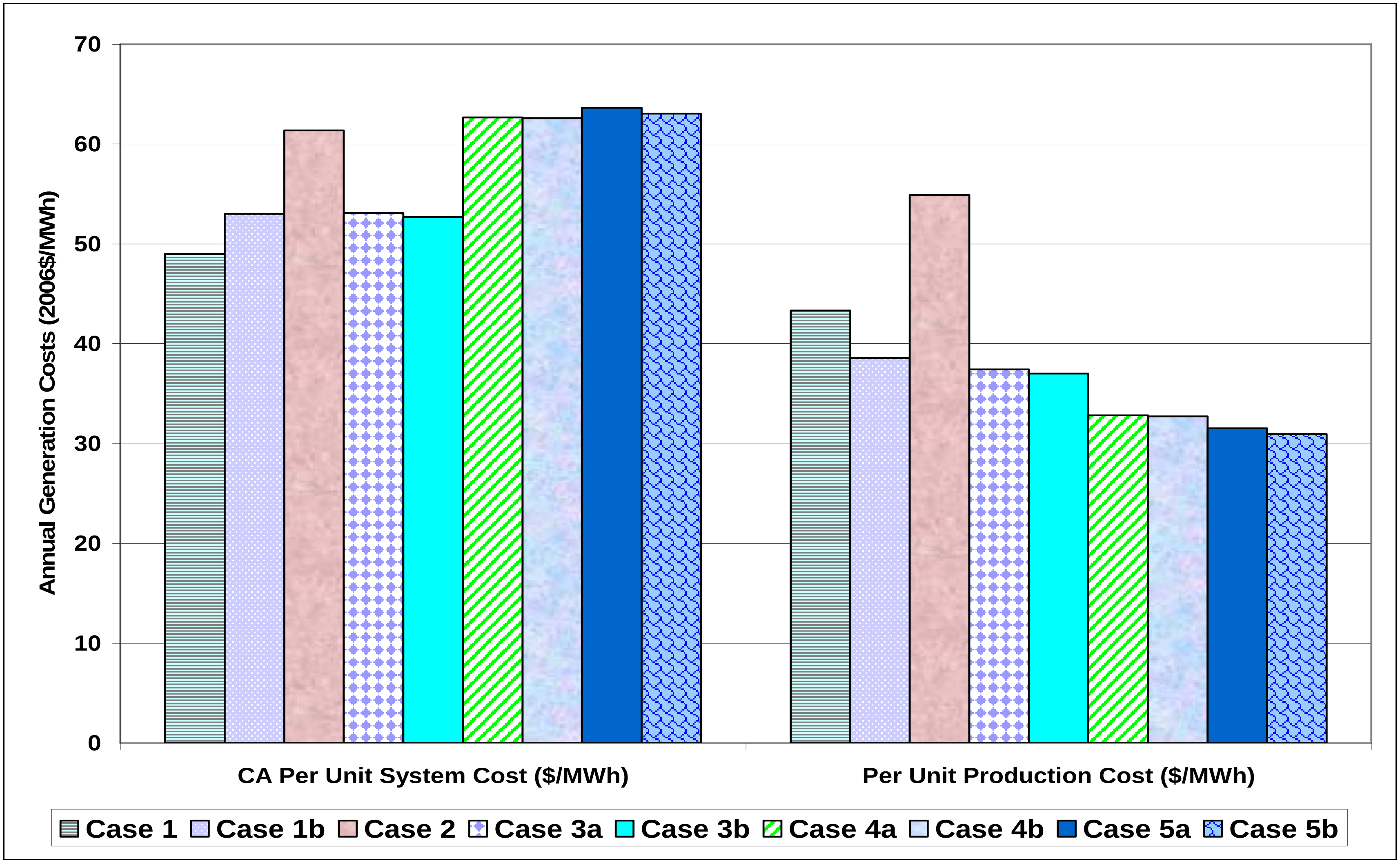
Source: Energy Commission Scenario Project

Figure ES-4: California Generation Cost Comparison Across Cases on a Total Cost Basis



Source: Energy Commission Scenario Project

Figure ES-5: California Generation Cost Comparison Across Cases on a Per Unit Cost Basis



Source: Energy Commission Scenario Project

CHAPTER 1: INTRODUCTION

1.1 Objective

The purpose of this study is to examine the implications of resource plans featuring very high penetrations of energy efficiency measures and renewable energy generation in California and the U.S. portion of the Western Electricity Coordinating Council (WECC). Among the variables of interest is the reduction in greenhouse gas (GHG) emissions compared to what might be expected without high penetrations in efficiency and renewables. The GHG reduction potential demonstrated here is limited to carbon reduction because the GHG reductions modeled are associated with reductions in fossil based electricity generation. The reductions in fossil generation that accompany increased penetrations of efficiency and renewables are attributable to the displacement of production from some existing generation facilities as well as the deferral or elimination of some anticipated fossil facilities. The study does not attempt to identify the optimal penetration of efficiency and renewables, but rather, explores how combinations of increases in penetrations in California and the Western Interconnection (also referred to as "the West") affect GHG emissions, resource requirements, transmission requirements, and cost in those geographic areas.

1.2 Approach

This study uses some of the same techniques that utility resource planners would use to determine how to select a specific resource addition to fit resource needs at least cost. However, rather than selecting among a broad set of generation technologies, perhaps using several steps to screen out poor candidates, and then studying other generation technologies for the optimal fit with existing resources, this study uses a different approach:

1. It is a "top down," policy driven approach rather than a "bottom up" load serving entity (LSE) resource selection driven approach.
2. It is a physical system representation approach rather than a control area-by-control area, or LSE-by-LSE, representation approach.
3. It attempts to be location relevant on locating resources and identifying location-specific resource mixes based upon physical location of resource potential (solar, wind, geothermal).

The type, amount, and general location of energy efficiency, end-user distributed generation, and power supply resources—both conventional and renewable—are different than the typical resource planning study because of the WECC-wide scope of this study and its goals to evaluate very high penetrations compared to current requirements. This study drew upon broad assessments of potential prepared in other studies.

Once the broad themes of several scenarios were established, a combination of techniques was used to develop viable resource plans. Production costing and power flow assessments trace through the consequences of high levels of "must-take" resources like energy efficiency, rooftop solar photo-voltaic (PV), and supply-side solar and wind that are not dispatchable. The entire Western Interconnection (WI), or WECC, was analyzed in all cases, even though for some cases only the California portions were modified for a preferred set of resource additions compared to the reference cases. A topology was used which allowed the prediction of physical results for each of 10 geographic regions in California and 19 geographic regions outside California that are generally combinations of control areas (transareas) in the U.S. portion of the WECC. In some instances, large control areas were split into parts.

1.3 Methodology and Modeling Tools

GHG emissions from the electric sector will depend on the composition of resources available, the performance of the resources available, the economic dispatch of the resources subject to the must-take requirements of certain resources, and the presumption of a system infrastructure that makes the identified dispatch viable from a reliability standpoint. For this study, the selection of the preferred resources available is largely determined outside any modeling or optimization framework. Rather, the selection of preferred resources is composed based on known or proposed policy standards, known near-term implementation plans, and judgment based upon the viability of efficiency and renewable resources by location. The non-preferred resources were assumed to follow the Global Energy Decisions (GED) Fall 2006 reference with the adjustment that generic additions rendered unnecessary by the aggressive adoption of preferred resources were backed out. The degree of deferral or elimination of these generic resources differed by scenario; the more aggressive the scenario in its use of energy efficiency and/or renewables, the greater the deferral of these generic additions, and vice versa.

The performance of energy efficiency and generation resources available for system dispatch were created based upon the best available information. All other assumptions regarding the loads and resources of the Western Interconnection were based on GED's Fall 2006 reference case. For California, energy efficiency potential and costs were based on the most recent energy efficiency potential study prepared collaboratively as part of the California Public Utility Commission's (CPUC's) administration of energy efficiency programs for the three major investor-owned utilities. For the Rest-of-WECC, where no such efficiency potential study is known to exist, efficiency levels were assumed up to the limit found feasible in the Clean and Diversified Energy Advisory Committee (CDEAC) reports. Performance attributes of rooftop solar photo-voltaic and supply-side renewable generating technologies were developed from actual recorded performance data where available, supplementing credible analytic studies.

The dispatch of the system was achieved through the application of the Global Energy Decisions *Market Analytics* software tool, especially the production cost engine PROSYM using the resource mix and resource characterization inputs determined as just described. The PROSYM model simulates an economic dispatch of the western electric system subject to the presumed dispatch of must-take resources such as wind, PV, etc. The viability of the network infrastructure to support the dispatch of the system was achieved by interleaving the identification of constraints in PROSYM runs with the results of power flow studies performed using the General Electric Positive Sequence Load Flow (PSLF) tool. The PSLF tool was also used to specify new transmission that is under development and new transmission that was identified as needed based on projected retirements.

Production cost modeling and power flow assessments require large quantities of information beyond the details of the preferred resource types around which the specific cases are designed. These take the forms of basecase or reference case datasets for the production cost model (PROSYM) and the power flow assessment tool (PSLF). Such datasets have been drawn from previous studies and have been updated to some degree, especially in elements thought to affect the credibility of the cases being examined. While a set of sensitivities has been investigated for each of nine cases, these results do not cover all uncertainties about inputs, much less model-specific idiosyncrasies.

1.4 Anticipated Insights

This project builds upon resource assessments conducted by other parties in other proceedings, but attempts to improve the rigor of the assessment. For example, the CPUC and the California Energy Commission (Energy Commission) have previously conducted assessments of high in-state renewables, but these studies have not reflected local capacity requirements or qualifying capacity rules in their development of resource plans, nor have they attempted to evaluate high levels of energy efficiency and the interactions between energy efficiency and renewables development. Similarly, the CDEAC process developed a sound summary of the potential for energy efficiency and renewable development throughout the West, but did not have the resources to conduct production cost modeling and other assessments to determine the interaction between these two elements of a GHG reduction strategy. Neither of these studies undertook the effort to estimate the GHG reduction consequences of various levels of preferred resource penetration.

By attempting to prepare electrically correct resource plans and to assess for both within California and West-wide variants of the preferred resource types, this study may reveal new insights that have not been previously understood. Such insights may provide an improved basis for policy maker decision-making. Insights may contribute to near-term policy decisions, or they may illuminate modeling issues that should be investigated with follow-on studies. The anticipated insights may reveal interactions between energy sectors or regions that were missed in previous analysis, model relationships that should be further explored in subsequent analysis, and issues that have direct policy implications.

As an illustration of expectations versus results, at the outset of this project, the project team designed scenarios to understand how large penetrations of preferred resources would affect operation of fossil power plants and the GHG emissions from these plants. Alternative scenarios examining California-only and West-wide versions of these GHG reduction strategies seemed useful in taking steps to understand how broader participation in GHG reduction strategies would affect carbon emissions, since there are already a variety of multi-state mechanisms being developed to pursue these objectives in the absence of a national strategy or policy commitment. The results to date reveal interesting changes in the levels of electrical energy imported into California when the non-California West pursues these strategies. These results may lead to the need for further studies to determine how least-cost dispatch within the integrated Western Interconnection utilizes existing coal and natural gas-fired generators even though preferred resources are added with the expectation that they are displacing fossil-fired generation.

1.5 Anticipated Limitations of Results

This project provides useful information, but the need to produce the results within the available time and budget imposed limitations on data assumptions, modeling assumptions, and uncertainty characterization assumptions.

- The data assumptions suggest imprecision in the results and indicate that the results are not useful as point estimates.
- The modeling assumptions suggest limitations in the representation of the electric system physical operations, market operations, and regulatory operations and thus imply that one should exercise caution in deciding which policy questions these results can meaningfully address.
- The uncertainty characterization assumptions suggest that results are likely to be sensitive to the incorporation of additional sources of uncertainty; thus, readers should exercise caution in making pronouncements that imply that the results would carry through even if additional sources of uncertainty were evaluated.

While the project enhances efforts to date in identifying the potential contribution of preferred resources to GHG reduction in California and the West, the limitations on assumptions constrain the immediate usefulness of the results to support specific policy decisions. In addition, the physical perspective design of the study reduced the need for most of the detailed assumptions that would have been required to conduct the modeling on an LSE-by-LSE basis.

Taken together, these three sources of assumptions, and the project design limitations, indicate that one should exercise caution in applying the results generated to date, because work has not yet been performed to evaluate whether the results produced will be robust as the limiting assumptions are addressed.

Chapter 9 describes in more detail the limitations imposed by the data assumptions, modeling assumptions, and uncertainty characterization assumptions, but some examples of assumptions will be presented now. These simple examples are intended to indicate why the assumptions are important and how considering the limitations imposed by the assumptions is important as one considers how the results presented to date may be usefully applied.

Data assumptions include those assumptions that are made in defining scenarios and those assumptions that are made in constructing data from imperfect data sources. An example of a scenario definition assumption in this study is the presumption that the 20 percent of peak load reduction asserted in the CDEAC report and used in this project to define an energy efficiency scenario for Rest-of-WECC is economically viable. While the CDEAC efficiency work group drew upon the expertise and judgment of noted efficiency experts, a technical and economic potential study was not available to the work group for most western states. Whether the 20 percent efficiency can be achieved by 2020 at the cost assumed in this project is a question that cannot be answered. California's own experience with many years of many types of energy efficiency codes, standards, and programs suggests that it is feasible, but differences in climate, policy, and regulation make any cost estimate speculative.

An example of a data assumption limitation is the hourly production profile of rooftop solar PV outside California. There are extremely limited data on actual hourly outputs sufficient to devise average monthly production profiles and the variations around such averages that might be expected from rainfall, clouds, and haze. Given the California Solar Initiative and other solar PV programs in Nevada and Arizona attempting to achieve thousands of megawatts (MW) of installed capacity, this technology plays an important part in this study, but the data used were synthetic modeling results obtained from the National Renewable Energy Laboratory (NREL). These types of data limitations should motivate:

- Further efforts to corroborate data and assumptions with other western states;
- Further efforts to improve upon the characterization of generation technologies, including the capture of realistic opportunities for technology performance improvement; and
- Further efforts to understand performance sensitivities and narrow cost estimates.

The PROSYM production cost simulation tool and the PSLF electrical system modeling tool were the primary modeling tools used in this study. The tools depict the economic and electrical operation of the system, respectively, and thus each provides an important contribution. However, using the two tools in concert over a geographic region that spans utilities, control areas, and states requires that modeling assumptions be made to coordinate generation expansion planning and transmission system planning. Introducing new resource expansion plans into PROSYM on a zone-by-zone basis is relatively straightforward, but ensuring that the electric system modeling of the resource additions is reasonable requires additional information and assumptions. Specific improvements could include better resource and technology characterization, including:

- Identification of specific resource locations by zones and within zones throughout the West,
- Better depiction of intra-zonal congestion assessment and remediation, and
- Better evaluation of inter-zonal infrastructure alternatives.

This study has not addressed a wide range of data and model relationship uncertainties. Natural gas prices, hydrologic conditions, and intermittent resource variability have been examined in limited stochastic exercises, but the broader implications of fundamental uncertainties have not been addressed. Examples of sources of uncertainty that could significantly affect the results of this study include:

- Uncertainty in the rate of technological change of respective generation technologies,
- Uncertainty in model relationships attributable to future state and federal regulatory mechanisms, including carbon control regulations,
- Uncertainty in the cost of accommodating distributed and remote resources into the grid, and
- Uncertainty in future demand attributable to electric vehicle deployment.

Finally, the decision to model the physical system rather than modeling the system on the LSE-by-LSE level of detail precludes certain uses of these results. The results as presented provide no indication of how the portfolios of individual LSEs might be designed or what is best for any one LSE to pursue. The load-based GHG control strategies being examined by the CPUC as part of Assembly Bill 32 (Nuñez), Chapter 488, Statutes of 2006, implementation include load-based approaches. While this study encompasses all of those loads, it aggregates the loads into seven transareas in California. These seven load transareas are adequate for depicting the physical operation of the electric system for some purposes; however, these seven transareas have more than LSEs. If California implements a load-based GHG reduction strategy, each of the LSEs will have its own unique GHG emission reduction requirements and its own unique approach to compliance. While one might expect that these LSEs will pursue energy efficiency and renewables as part of their compliance strategies, an individual LSE's strategy may deviate significantly from the scenarios presented here. From this perspective, these results may be useful to illustrate the aggregate consequences of a large number of LSEs pursuing energy efficiency and renewables as a compliance strategy, but are not useful for evaluating an individual LSE's strategy.

Data, modeling, and uncertainty assumptions significantly affect the results presented in this study. The extent to which the assumptions affect the results is uncertain as the sensitivity of the results to changes in the assumptions has not been assessed. It is conceivable that some assumptions may exacerbate one another so that the combined effect of varying several assumptions at once could have dramatic effects on the results. The results are available for the composite of all loads in geographical areas, not for LSEs which have been the primary focus of energy regulatory decisions on resource preference. Therefore, while the results are interesting and may prove to be robust with further testing and exploration, policy discussions based on the results provided to date should be cautious and should consider the potential ramifications and limitations that the project design and assumptions impose.

1.6 Status of Analysis Relative to Expectations

Three elements of the original scope of work are not yet complete and will be provided at a later date. These are:

- Case variants that illustrate how retirement of aging thermal power plants might require replacement capacity or transmission upgrades in specific locations to satisfy local capacity requirements,
- Analysis to show the possible effect of the much lower power plant fuel consumption projections on market clearing natural gas prices from a scenario that presumes a very large penetration of energy efficiency impacts and supply-side renewable generation, and
- Projections of water used in once-through cooling and water consumed in power generation by thermal power plants.

This report is written in a manner that shows where these topics eventually will be placed in the final report once the work is complete and documented. In this draft of the final report, the contents of those sections state that the work is not yet complete.

1.7 Organization of This Report

The remainder of this report is organized into nine additional chapters and numerous appendices.

Chapter 2 provides a description of the thematic scenarios. It begins with a broad overview of the nine scenarios, then uses a section for each scenario to the describe the quantitative attributes distinguishing that scenario from others. Appendices A and B provide additional detail on features of the alternative scenarios and Case 1B—the starting point for the development of all of the preferred policy scenarios.

Chapter 3 summarizes the metrics used during the assessment and in reporting the results. The concepts represented are easily understood and common to many other studies, but the detailed specifications used in a study vary throughout the industry. This chapter explains the specific metrics used in this study.

Chapter 4 summarizes the specific performance, cost, and location characteristics of the resources used to define the scenarios. Additional details for some resources are documented in Appendices E through G.

Chapter 5 provides an overview of the methodological steps used to develop or to assess the scenarios.

For each of the nine scenarios, Chapter 6 summarizes the final load and capacity resources and provides the results as annual energy production, natural gas and coal consumed, GHG emissions, generation costs, and criteria pollutant emissions. Additional details are provided in Appendices C and D.

Chapter 7 evaluates the implications of high efficiency programs and renewable generation for California and Rest-of-WECC by comparing pairs of scenarios. The evaluation compares the mix of resources serving load, generation cost, and GHG emission consequences of these broad categories of preferred resources.

Chapter 8 summarizes the sensitivity cases that were evaluated. The implications of generation cost resulting from high and low fuel prices relative to the basecase were investigated for all scenarios for all years. “Shocks” in the form of single year high and low hydro-electric generation and extremely high natural gas prices were investigated for year 2020. This final year was selected to discern the implications once the characteristics of the scenarios were fully deployed.

Chapter 9 identifies limitations on the use of the results due to the design of the study, and data, modeling, and uncertainty characterization issues that were encountered.

Chapter 10 provides a series of steps that might be undertaken next to:

- Augment the present study in light of the results to date,
- Improve data and modeling to overcome or moderate some of the limitations identified in Chapter 9,
- Allow the results to be more readily compared to other studies, or
- Simply to make the results more useful.

It also recounts “missing elements” of the original scope of the study that are still underway, but which could not be completed in time for this report.

A series of appendices augment the detail in this report. In addition, since the fundamental PROSYM production cost model results are too detailed to be rendered into the form of the printed page, some appendices describe how to download electronic spreadsheets from the Energy Commission's Web site.

CHAPTER 2: DEVELOPMENT OF THE CASES TO BE ASSESSED

This chapter describes the process that was followed to design a series of thematic scenarios emphasizing the preferred resource types. These broad scenarios were later fleshed out in detailed "cases" that were implemented in the form of PROSYM production cost model datasets and evaluated for the period 2009 to 2020.

2.1 Designing a Sequence of Cases to Evaluate Preferred Resource Types

This study designed a series of alternative resource plans that successively increase the levels of preferred resource types (energy efficiency, demand response, rooftop solar photovoltaic (PV), and supply-side renewable generating technologies.) Each of these alternative resource plans is referred to as a "case." From the beginning, the study design envisioned two "bookends" and some intermediate cases.

2.1.1 Bookends and Intermediates

Despite the existence of renewable portfolio standard (RPS) requirements in many Western states and active energy efficiency programs in some states, the utilities in most of these states have not achieved their respective preferred resource targets and therefore, an appropriate starting point for this analysis is a case that reflects the disappointing results to date. Case 1 (Current Conditions) is designed to reflect this conservative penetration of preferred resources. This case assumes there are continuing shortfalls in achieving EE, DR and renewables with any resources needs satisfied mainly by conventional resources, e.g., pulverized coal, gas-fired combined cycle, and combustion turbine.

At the other extreme, one could imagine a situation where California and the West meet preferred resource goals that substantially exceed the goals currently reflected in statute. The Western Governor's Association established a broad goal for renewables and created an ad hoc organization Clean and Diversified Energy Advisory Committee (CDEAC) to identify a strategy to achieve it. CDEAC developed a series of technical reports and a lengthy set of overarching recommendations by May 2006. WGA adopted a resolution in June 2006 endorsing the recommendation put forward by CDEAC. In January 2007, the governors of five Western states signed onto a Memorandum of Understanding in which the governor pledges to pursue a wide range of measures with the goal of major reductions in GHG emissions. Subsequently, the Canadian province of British Columbia has agreed to pursue a similar path. Thus, a case assuming very high levels of the preferred resource types across the West should logically be examined.

Having established these "bookends," a series of intermediate levels of these preferred resource types were developed. In addition, since this is a study funded by the Energy Commission, there is a special interest in the implications of California-only versus

West-wide policy initiatives. As a result, all of the cases speculating about increased levels of energy efficiency, renewables, or both were developed and then modeled in two versions – one for California alone and one throughout the West.

As is explained in more detail later in this chapter, each case examined the transmission requirements associated with the generation mix that was developed. Where existing transmission was found to be insufficient to support the assumed level of development, especially renewables in a specific transarea, appropriate upgrades to the transfer capacity from that transarea to adjacent ones were developed. The zonal topology used in PROSYM is explained in greater detail in Section 5.1. In a few specific instances, intra-zonal transmission additions known to be required to support distributed development of renewable generation were evaluated. Even though these intra-zonal transmission upgrades are not needed to run PROSYM, their costs were identified and included in the results database.

2.1.2 Technologies Excluded from the Design

A reader comparing the description of the thematic scenarios in Table 2-1 to that included in the initial staff report published in January 2007 will note that scenarios 6A and 6B addressing retirements of aging power plants are no longer included. During the assessment of the retirement of these aging power plants, it was decided that standalone scenarios were inconsistent with the thematic qualities of the other scenarios. Instead, each of the thematic scenarios should be investigated in the context of alternative means of retiring aging power plants and developing suitable replacements. This effort is not yet complete, so its results are not fully included in this report. When this work is completed there will be at least one additional case for each of the California thematic scenarios that quantify retirements following the general theme of the scenario itself. So in a case featuring conventional resource development, there is a conventional replacement strategy that will be provided. Similarly, in a high renewables scenario, there will ultimately be additional case results for various transmission and renewables development packages

Distributed generation is reflected in the design of the thematic scenarios only through rooftop solar PV. All of the other forms of distributed generation seemingly involve technologies that require fuels, that involve selecting technologies that match electrical output with thermal loads in buildings and industrial settings, or other considerations that were beyond the scope of this study. Further, there is active consideration of distributed generation as a means to improve distribution system planning, which requires a variety of tools that make use of far more geographic detail than this project could attempt to include. For these reasons, distributed generation was excluded from the design of the scenarios with the exception of the rooftop solar PV technologies that are pushed as part of the California Solar Initiative. To have evaluated distributed generation with just the production cost model and transmission power flow assessments would have been too incomplete to provide a meaningful assessment of the implications of this category of preferred resource.

2.1.3 Overview of the Thematic Scenarios and Related Cases

Using this process, the study team designed nine thematic scenarios that involve different levels of energy efficiency, end-user distributed generation, demand response, and supply-side renewable generation. Each of these were to be evaluated using both "basecase" assumptions and a set of sensitivities. Because the variations from the basecase scenario creates a family of related cases, we use the term "case" to describe all of the members of the set of resource plans that were evaluated.

Table 2-1 summarizes the key features of the parent scenario that will be assessed with both "basecase" values and alternatives creating a series of sensitivity cases. Each of the cases is defined in terms of the nature of the energy efficiency, demand response, rooftop solar PV, and supply-side renewable generation featured in the parent scenario. An A or B designation for a case indicates its geographic scope; "A" cases are California alone, while "B" cases are both California and the entire Western Interconnection (WECC-wide). Even though Case 1 does not follow use this convention, it encompasses the entire Western Interconnection.

The remainder of this chapter reviews each one of the parent scenarios and the principal features used to design it. Appendix A provides an overview of the elements of these nine parent scenarios in a format that allows cases to be compared with one another in a greater level of detail.

2.2 Case 1 – Current Conditions

Case 1 resource plan input assumptions were based in large part on the Global Energy Decisions Fall 2006 WECC Power Market Reference Case (Global Reference Case). This case is prepared independently by Global Energy Decisions (Global) and provided to numerous clients. The case is derived from (a) an extensive data base of existing generation and transmission facilities in WECC, which data base is developed and maintained by Global, (b) the MarketSym model (a well know hourly chronological unit commitment and dispatch model which is also used by the Energy Commission), and (c) modeling "set-up" and future assumptions developed by Global Energy professionals based on their extensive knowledge of WECC Power Markets.

Table 2-1: Overview of Preferred Resource Assumptions in Each Thematic Scenario

Thematic Scenario	Energy Efficiency	Demand Response	Rooftop PV	Renewables
1 – Current Conditions	No uncommitted EE, so only committed programs included in load forecasts	Existing program capability	Negligible	Installed projects continue to fall short of RPS goals across the West
1B – Current Requirements	IOU 2009-2011 goals	IOU proposed program expansions	Existing IOU subsidy levels	State renewables req. as of fall 2006
2 – Sustained High Gas and Coal Prices	Case 3A for California; about 5% for Rest-of-WECC	Case 1B	Case 1B	Slight shift to coal or geothermal in specific transareas
3A – High EE in California only	2006 Itron report - economic potential	Case 1B	Case 1B	Case 1B
3B – High EE in both California and Rest-of-WECC	Case 3A for Calif; for Rest-of-WECC - 11% of peak load	Case 1B	Case 1B	Case 1B
4A- High Renewables in California only	Case 1B	Case 1B	IOU subsidies and effective marketing in California only	Expands to about 30% of customer energy sales
4B – High Renewables in both California and Rest-of-WECC	Case 1B	Case 1B	Case 4A and expansion in AZ and NV	Expands to about 25,000 MW similar to CDEAC report
5A- High EE and Renew in California only	Case 3A	Case 1B	IOU subsidies and effective marketing	Same level of capacity as Case 4A
5B – High EE and	Case 3B, which	Case 1B	Case 4B,	Same level of

Thematic Scenario	Energy Efficiency	Demand Response	Rooftop PV	Renewables
Renewables in both California and Rest-of-WECC	is Case 3A for Calif; for Rest-of-WECC - 11% of peak load		which is IOU subsidies and effective marketing in California, and AZ/NV expansion	capacity as Case 4B

2.2.1 Global's Fall 2006 WECC Power Market Reference Case

A large portion of the input assumptions in the Global Fall 2006 Reference Case reflect conventional utility thinking and projections as gleaned from resource plan filings and other sources. As will be discussed in the next section, some elements of policy preference are hidden within the projections that are made public. For example, the degree of energy efficiency impact already incorporated within load forecasts is relatively poorly documented. Existing and new resource additions can be gleaned from control area filings to WECC each year.

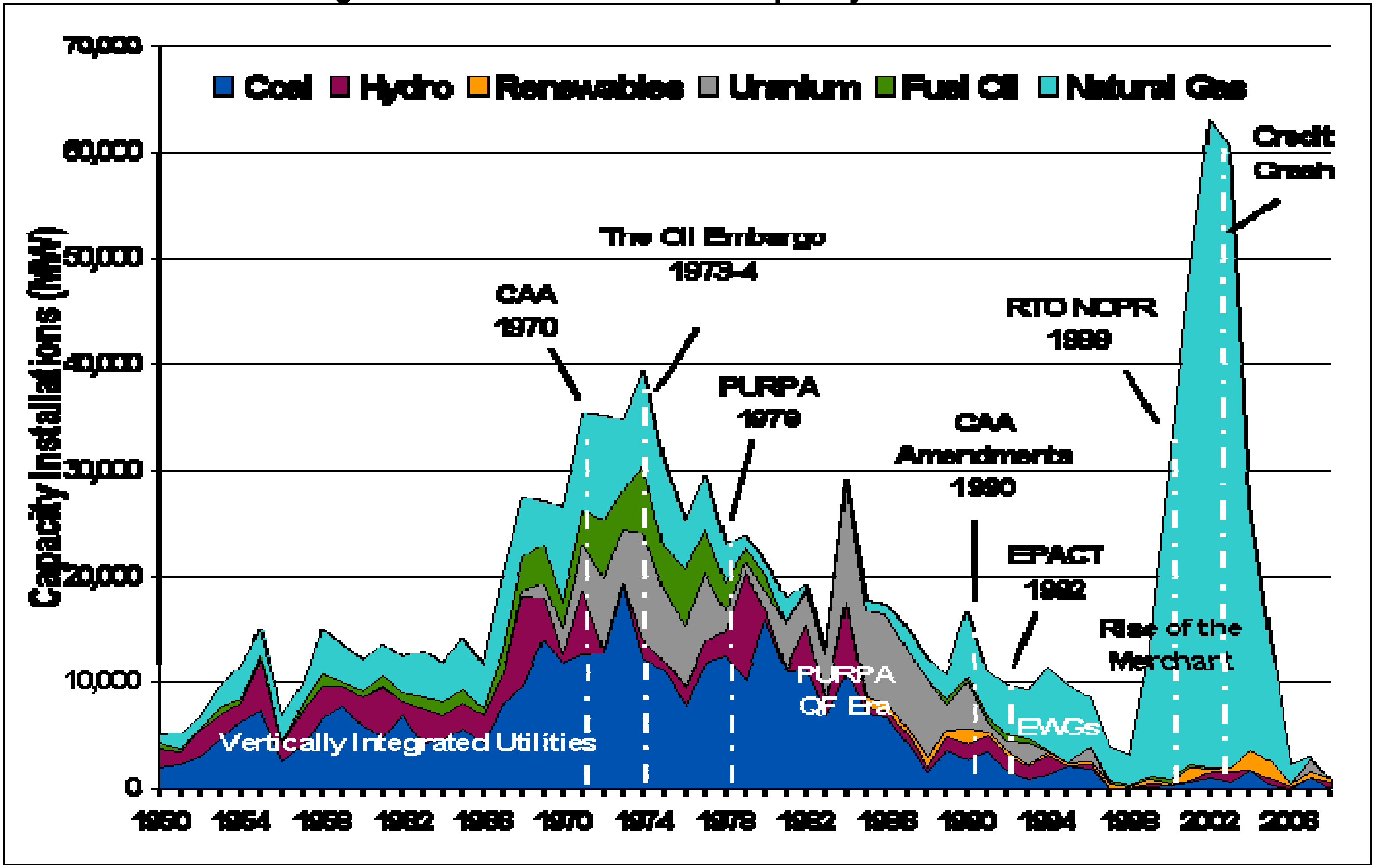
The basic premise of the Global Reference Case is that future resource needs in the WECC will be primarily met with the lowest cost resources. Recent experience in North America shows us that the vast majority of new resources that have been built have been gas-fired generation. Figure 2-1 summarizes the North American capacity additions since 1950.

Renewable energy is a desirable product, as reflected by the proliferation of renewable portfolio standards in various states to encourage its development, but these technologies face significant hurdles. Wind, for example, is not given much capacity credit for reliability purposes in most utility analyses. Many renewables are located where significant transmission would need to be built to integrate the power into the backbone transmission system. Production tax credits can help the economics of such projects, but it is not clear if the credits will be available in the future. While renewable energy has been a preferred resource for utilities for many years, evidence is that the industry has been able to bring on limited amounts as indicated in Figure 2-2. The largest amounts of renewable capacity have been brought on line when tax credits have been available.

Based on this logic, the Current Conditions case assumes that 750 MW of new renewable will be built every year in the WECC. Global assumes this development of new renewable is primarily wind.

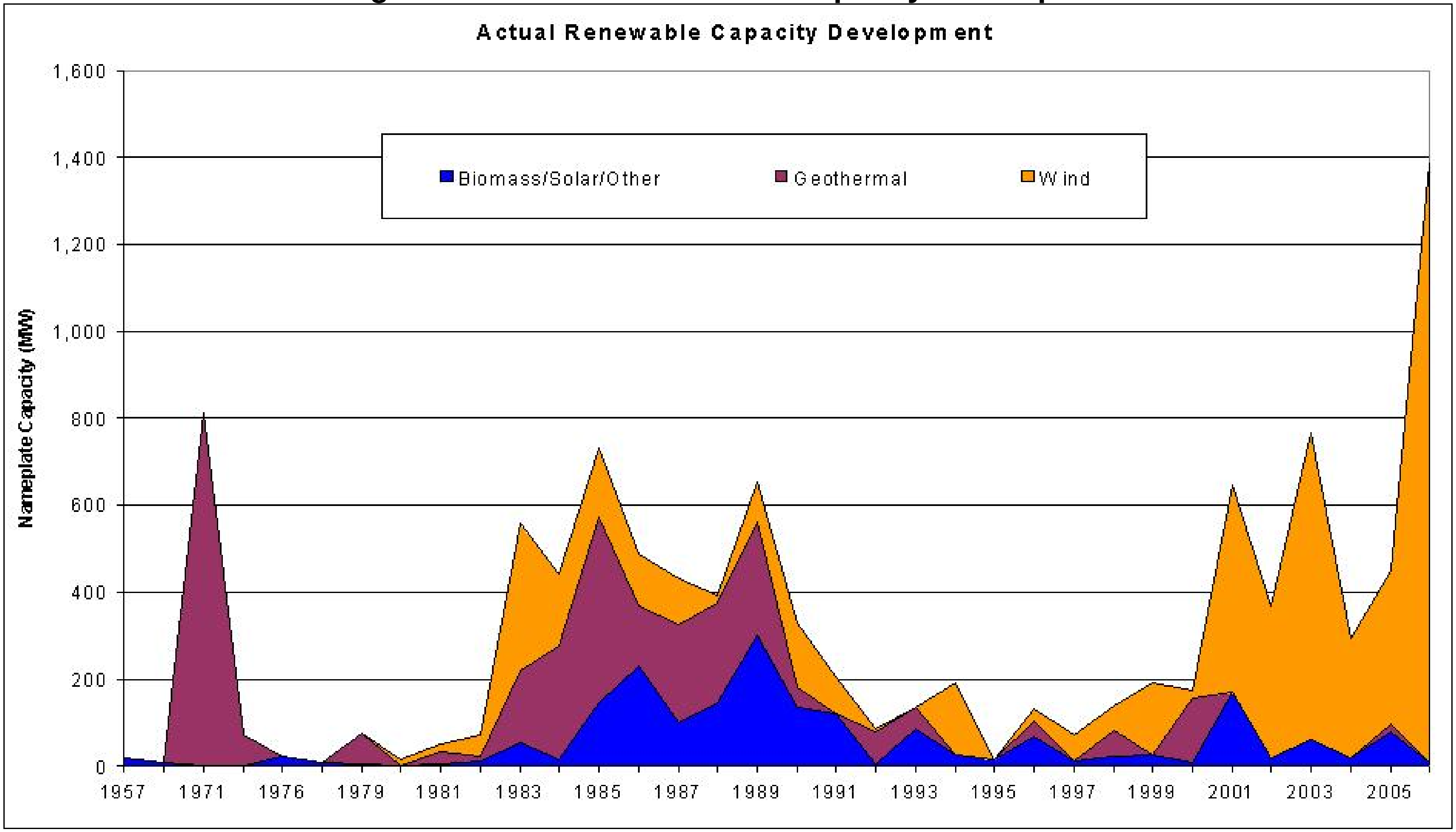
Global's own natural gas price projections are linked to an oil price projection also developed by Global analysts. Both were slightly lower than the EIA basecase that was released in preliminary form in December 2006. Figure 2-3 show this natural gas price forecast in terms of Henry Hub prices. PROSYM actually uses natural gas prices developed for each of a dozen market areas, which have their own basis differentials from Henry Hub. In the topology configuration, each power plant is associated with one of these market zones, which then determines how that power plant's costs are modeled in the dispatch logic of the model.

Figure 2-1: North American Capacity Additions Since 1950



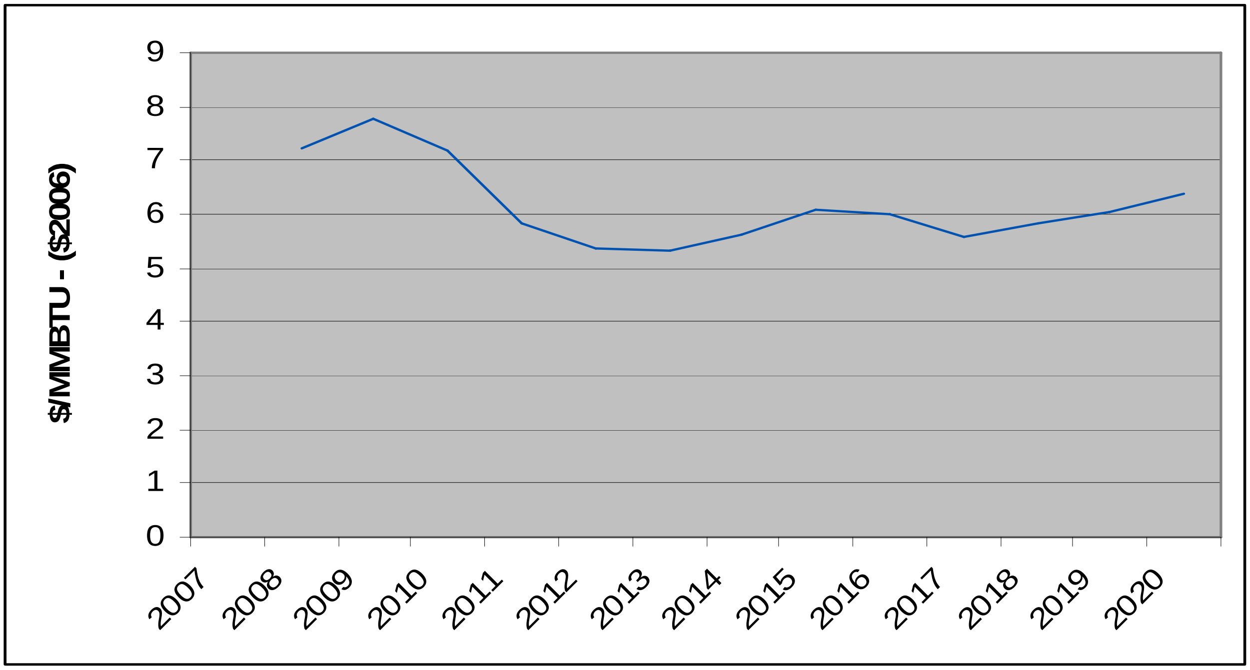
Source: Global Energy.

Figure 2-2: Actual Renewable Capacity Development



Source: Global Energy.

Figure 2-3: Basecase Gas Price Forecast for Henry Hub ($2006)



Source: Global Energy

2.2.2 Modifications to Create Case 1

Starting with the Fall 2006 WECC Power Market Reference Case, Energy Commission staff recommended changes in certain aspects of the modeling set-up and input assumptions. Three principal changes were recommended:

- Minor adjustments in model topology;
- Changes to the natural gas price projections; and
- Switch to Energy Commission load forecasts for California transareas.

The model topology change recommendations were made to reflect the Energy Commission staff version of model topology (which changes resulted in more zones being modeled in California and some minor changes in path ratings in California).

The gas price change recommendation resulted from the Energy Commission desires to use a natural gas price forecast more closely aligned with the most recent U. S. Energy Information Administration (EIA) forecast of natural gas prices. In order to accomplish this change, Global Energy reran its natural gas price forecast model using a higher oil price forecast. This higher oil price forecast came from the most recent EIA oil price forecast. Resulting natural gas prices were quite similar to the EIA most recent forecast of natural gas prices.

The Energy Commission staff recommended using the latest Energy Commission forecast of California loads. [1] This created greater assurance of consistency with other staff assessment projects.

In summary, the Global Reference Case as modified to become Case 1 (Current Conditions) reflects a conservative penetration of preferred resources reflecting continuing shortfalls in achieving current statutory requirements for EE, DR and renewables and resource needs satisfied by conventional resources. This shortfall assumes that the rationales for such shortfalls are not resolved or corrected throughout the time horizon of the analysis.

2.3 Case 1B – Existing Requirements

Case 1B adjusts Case 1 to incorporate West-wide use of preferred resources. It is built upon Case 1 assumptions with the exception that there is a presumption of better success in meeting preferred resource requirements currently reflected in state statutes or regulations. Better success does not necessarily mean that all policy goals established for LSEs are satisfied. Renewable Portfolio Standards (RPS) and other policy goals of the various states are designed for LSE implementation, and have complex provisions that are beyond the scope of this study. The assumption that states meet their preferred resource requirements has ramifications for both the amount of preferred resources included as well as the amount of non-preferred resources excluded. The process for including additional preferred resources and backing out non-preferred resources is a two step process. Compared to the Case 1 starting point, step one overbuilds the resource plan by inserting preferred resources. Then, in step two "excess" resources are removed, considering the expected relative dependable capacity of conventional and EE and renewable resource additions, until the resource plan better satisfies resource planning objectives.

2.3.1 Preferences for Energy Efficiency and Demand Response

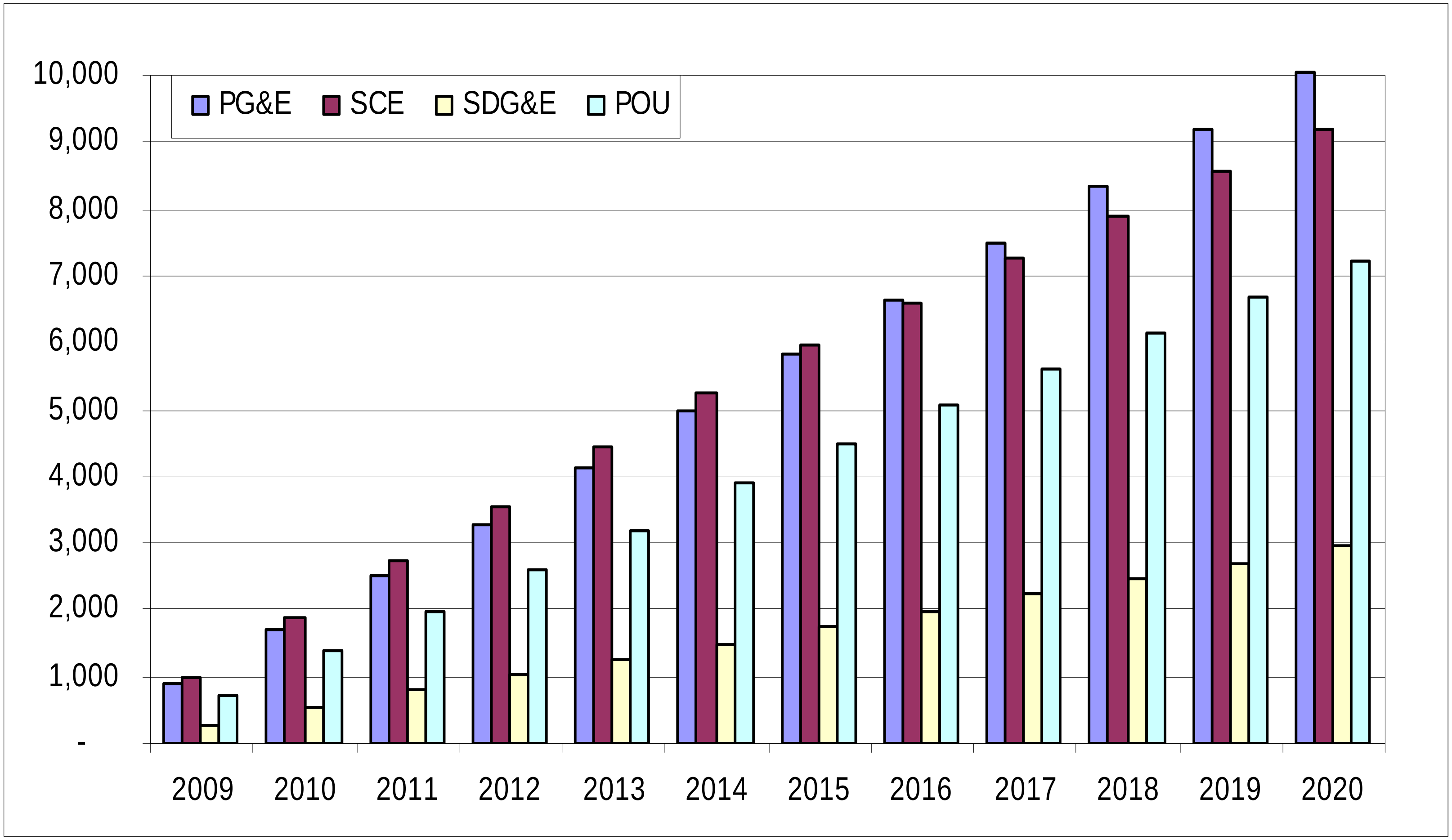
Energy efficiency (EE) was based upon the investor-owned utilities (IOUs) long-term procurement plans[2] for the years 2009 through 2016. These plans reflect annual EE additions at approximately 73 percent of the planned annual EE additions under the current program cycle (2006-2008). For the years 2017 through 2020, annual EE additions are assumed to be the same percent of sales as in the year 2016. The cumulative EE savings for 2006–2020 exceed the "Full Incentives" potential savings identified in the 2006 EE Potential Study.[3] The publicly owned utilities (POU) are assumed to achieve approximately 75 percent as much energy efficiency as a percent of the forecasted sales as the IOUs project. The cumulative EE achievements by IOU and for all POUs are summarized in Figure 2-4.

[1] California Energy Commission, Updated Demand Forecast, June 2006

[2] Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, 2006 Procurement Plan, December 2006, R.06-002-013 submitted to the CPUC. PG&E and SCE included alternative plans or assumptions. PG&E's "Current World" scenario and SCE's "Best Estimate" plan were used.

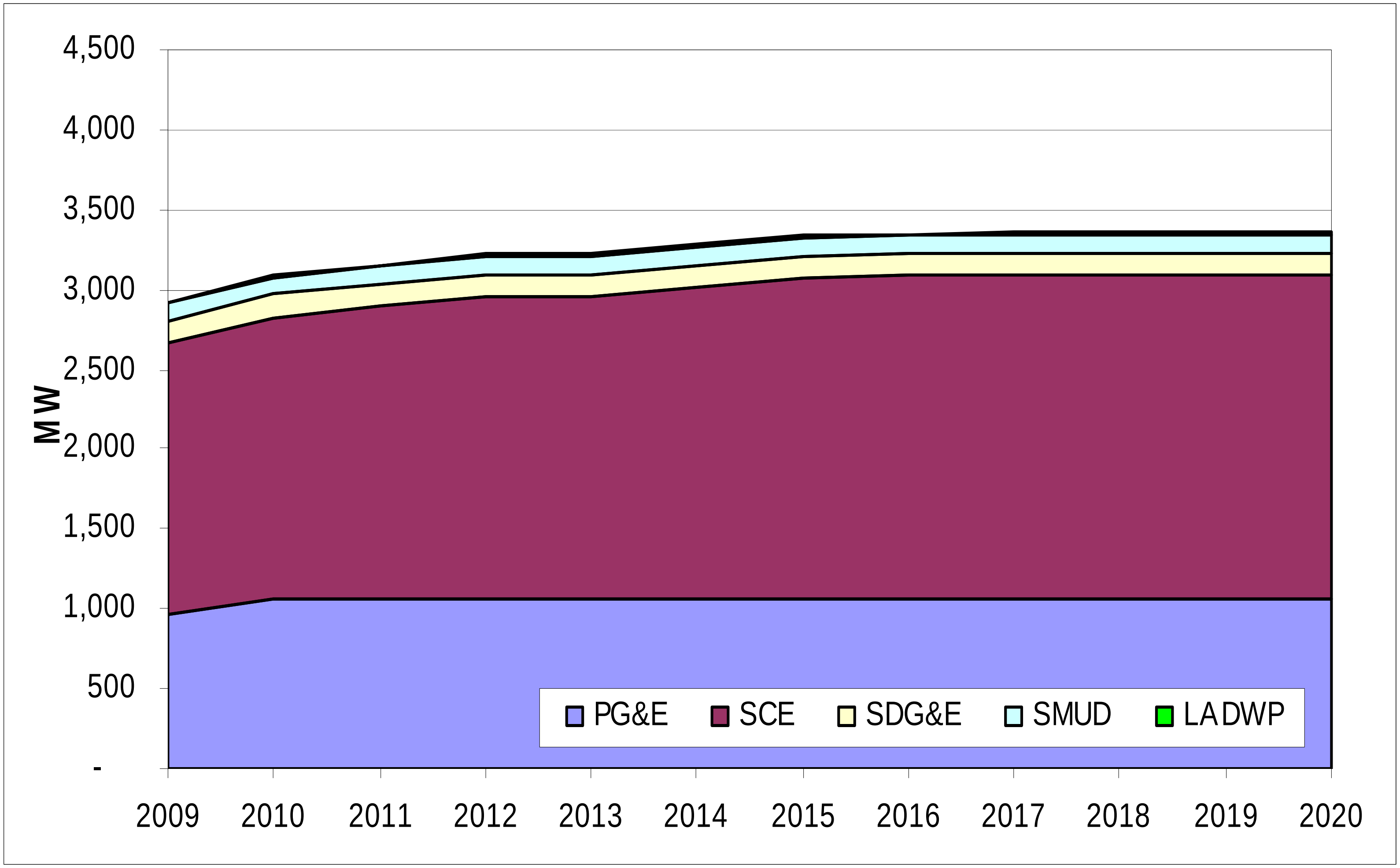
[3] Itron, KEMA, RLW, and AEC, May 2006, "*California Energy Efficiency Potential Study*."

Figure 2-4: Projected Cumulative Impacts of California Energy Efficiency Programs in Case 1B



Source: Navigant Consulting

Figure 2-5: Projected Cumulative California Demand Response for Case 1B



Source: Navigant Consulting

California IOU plans for energy efficiency and demand response do not necessarily satisfy the policy goals established by regulatory agencies. There are shortfalls that reflect disagreements about cost-effectiveness of measures and the delivery programs to consumers. Appendix F provides further details.

An LBL study of western utility integrated resource plans (IRP) found that energy efficiency was both embedded within load forecasts and part of the assumed resource additions to satisfy remaining load growth.[4] The degree to which loads were reduced for energy efficiency impacts was not well documented in most cases. Committed EE for the Rest-of-WECC was assumed to be embedded in the sales forecasts for the other states, so no incremental additions for Case 1B were included.

Demand Response (DR) is based on the utility submittals to the Energy Commission pursuant to the 2007 IEPR Demand Forecast Forms and Instructions Form 3.4 filings. The total state-wide demand response grows to approximately 3,200 MW by 2010. After 2010, only SCE showed growth in DR capacity. The DR capacity by year and utility is summarized in Figure 2-5. Appendix F provides further details.

2.3.2 Preference for Rooftop Solar Photovoltaic

Rooftop solar photovoltaic (PV) assumptions for California, Arizona and Nevada are based upon IOU compliance with state requirements, and with California and Arizona estimates further supported by Navigant Consulting's *California PV Market Assessment*, prepared for the Energy Commission's Public Interest Energy Research (PIER) renewables program, January 2007. Rooftop PV is a favored customer-installed energy generation technology in California supported by the California Solar Initiative created by California Senate Bill 1 in August 2006. The California Solar Initiative has a goal of achieving 3000 MW of rooftop PV by 2017.

Several alternative penetration scenarios were developed by Navigant and are described in more detail in Chapter 4. Table 2-2 provides the penetration used for Case 1B in California.

Table 2-2: Case 1B California Rooftop PV Penetration (MW)

Customer Class	2006	2010	2016
Residential	5	43	350
Commercial	58	140	482

[4] LBNL, August 2006, *Energy Efficiency in Western Utility Resource Plans: Impacts on Regional Resource Assessment and Support for WGA Policies*, LBNL-58271.

For the rest of the WECC, estimates of customer rooftop PV were prepared for Arizona and Nevada. Estimates for PV for Arizona were derived from a study completed by Navigant Consulting for the Arizona Department of Commerce – *Solar Electric Roadmap Study*, October 2006. Present incentives for PV in Arizona are provided by the electric utilities. The referenced study concluded that without additional incentives, Arizona rooftop PV additions would be only approximately 1 MW in 2016, growing to less than 40 MW in 2020, with those additions primarily due to industry advances rather than incentives or market conditions unique to Arizona. These current Arizona PV incentives conditions and these levels of customer-installed PV were assumed in Case 1B. Nevada customer-installed PV levels for Case 1B were assumed to be at levels that meet the Nevada state resource portfolio standards, with the PV contribution equal to 211 MW in 2015 growing to 243 MW by 2020.

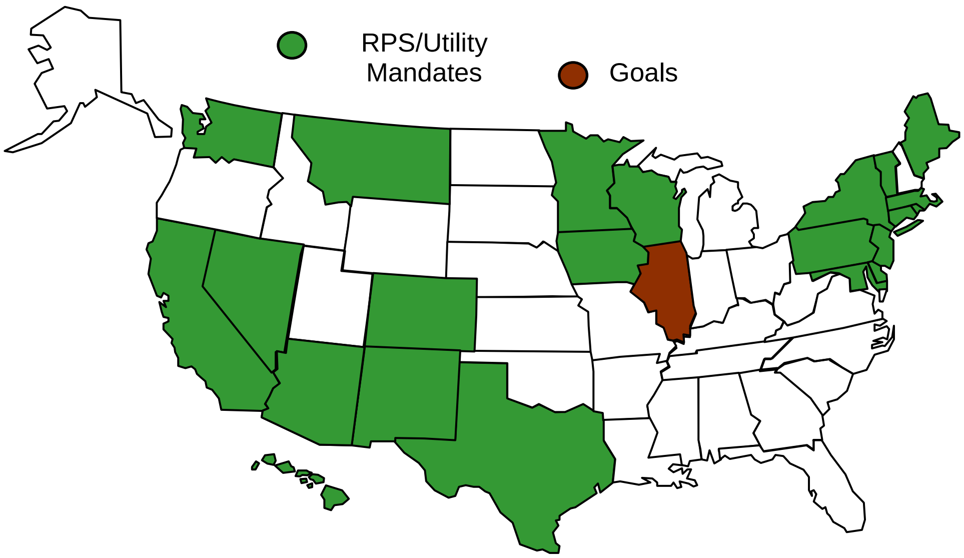
2.3.3 Preference for Supply-Side Renewable Generating Resources

Numerous states around the country have adopted one or more forms of renewable portfolio standard (RPS). Generally, these are complex statutes that establish a "mandate" for achieving energy or capacity from a specific set of resources, but with some kind of cost cap on the "above market" expenditures that utilities need not exceed in order to constrain rate impacts. Figure 2-6 provides a chart of the states with such requirements and a tabular listing of the target and date it is to be achieved.

Energy Commission staff have developed several projections of supply-side renewable resource additions for all WECC transareas using information directly from the three large IOU filings to the CPUC, other utility integrated resource plan filings, and staff judgment about the most likely path to achieve the RPS requirements in those states having such laws. This effort is necessary for any WECC production cost modeling effort or for transmission planning studies. This analysis was updated again in 2007, originally prepared as part of developing projections of natural gas demand for power generation for the Energy Commission's natural gas assessment efforts, but extended only to 2017. The Scenario project team extended the analysis to 2020 by extrapolating the growth in the last few years up through 2017 of the staff analysis.

The following subsections provide an overview of this effort for California and for the Rest-of-WECC.

Figure 2-6: Renewable Portfolio Standards by State as of April 2007



State	RPS Target
AZ	15% by 2025
CA	20% by 2010
CO	20% by 2020
CT	10% by 2010
DC	11% by 2022
DE	10% by 2019
HI	20% by 2020
IA	105 MW (2% by 1999)
IL	8% by 2013
MA	4% by 2009 (+1%/yr after)
MD	9.5% by 2022
ME	10% additional by 2017
MN	25% by 2025
MT	15% by 2015
NJ	6.5% by 2008, 20% by 2020
NM	5% by 2006, 10% by 2011
NV	20% by 2015
NY	24% by 2013
PA	18% by 2020
RI	16% by 2019
TX	5,880 MW by 2015
VT	New generation renewable 2005-2012
WA	15% by 2020
WI	10% by 2015

2.3.3.1 California Renewables

A review of the IOU 2006 Long Term Procurement Plans (public versions) was conducted to obtain each utilities estimate of current levels of RPS eligible production. In addition, these plans provide an estimate of annual incremental renewable energy production to meet individual IOU targets. Using this data and information regarding renewable energy projects and proposed transmission projects, staff made assumptions for each IOU regarding how they would meet state RPS obligations. Energy Commission load forecasts were used in annual procurement calculations.

Staff used Southern California Edison's (SCE) Best Estimated Plan as a guide to SCE's annual renewable energy procurement. Rather than assume that SCE will reach the 20 percent goal by 2011, staff used a one year lag time for SCE procurement, reaching the 20 percent goal in 2012. This date is consistent with estimates for transmission expansion in the Tehachapi region to allow for increased penetration of wind energy that is deliverable to SCE load.

Using Pacific Gas & Electric's (PG&E) Basic Procurement Plan estimates for renewable energy and the Energy Commission's 2006 load forecast, staff developed a renewable energy procurement assumption that assumed an equal percentage of renewable energy procurement each year from 2010 to 2013. While PG&E assumed that it would increase its total renewable percentage from 15 percent in 2009 to 20.2 percent in 2011, staff was more conservative, estimating that PG&E would reach the 20 percent goal in 2013.

Energy Commission staff used San Diego Gas & Electric's (SDG&E) Preferred Plan estimates for existing, planned and generic renewable energy for years 2007-2009. Using these estimates, the renewable energy percent climbed from 6 percent in 2007 to 13.8 percent for 2009. Beginning in 2010, staff used lower estimates for renewable energy procurement than did SDG&E. In the 2006 filing, SDG&E states that it has 16.4 percent of renewable energy under contract for 2010. Using the Energy Commission load forecast for 2010, staff calculated the amount of RE for 2010, then used a linear approach to SDG&E obtaining 20 percent of renewable energy by 2013 (as opposed to SDG&E reaching 22 percent by 2010 as the IOU claims). Staff's opinion on this renewable energy trajectory is based on the limited availability of in basin renewable energy, and is consistent with planned transmission expansion projects in Southern California.

For California publicly-owned utilities (POU), it was assumed they would work toward a RPS target of 10 percent by 2013. This estimate is based on staff's review of the current level of renewable production from POUs and POU renewable energy projects in development and announced in media reports. While POUs are not required by state law to provide customers with a specific percentage of energy from renewables, larger POUs (LADWP, SMUD) have set their own renewable energy goals. Staff considers the estimate of 10 percent by 2013 to be in line with POU renewable energy projections, if not slightly conservative.

Data obtained from the Energy Commission's Renewable Office staff estimated that 6.5 percent of 2006 POU delivered energy came from eligible renewable technologies (4,689 GWh). For staff's basecase, this amount of generation was assumed to continue and additional renewable energy was added by staff in order to meet a 10 percent target by 2013. To meet this goal, sufficient generic renewable additions were added after accounting for specific energy projects that are announced and in development.

2.3.3.2 Rest-of-WECC Renewables

A spreadsheet database was created to track renewable energy production, individual state renewable energy requirements, and generic renewable additions throughout the forecast period. For those states with RPS requirements, yearly loads (in GWh) for the utilities subject to each state's RPS were aggregated. Information on which states have RPS and a summary of the standards was acquired from the Database of State Incentives for Renewables and Efficiency (DSIRE) website. (http://www.dsireusa.org) Annual renewable production was then calculated from the simulation results using eligible technologies for each state, and any multipliers or credits were factored into the total renewable energy production for each state (for example: 1.5 kWh credit for in-state production of 1 kWh produced from solar technology). Yearly renewable targets for each state were compared to yearly production to determine if new renewable resources would need to be added to meet state mandates. In those states where production fell significantly short of the target, generic renewable resources were added to the basecase.

For those states with a RPS requirement in place, Energy Commission staff added renewable energy to the mix of resources for each state, prior to adding generic, non-renewable resources into. Out of state renewable energy additions were based on a review of each state's potential for renewable energy technologies, as outlined in the *Renewable Energy Atlas of the West*, published in July 2002. The atlas was produced and written by the Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, and the GreenInfo Network. The atlas served as a guide for evaluating the potential for renewable energy production from biomass, geothermal, solar, and wind resources. Estimates for annual energy production from each resource type by state are provided in the atlas. Staff used these estimates when adding generic renewable resources to this case, considering existing transmission and proximity to load centers when making the additions.

Figures 2-7 and 2-8 below illustrate where generic renewable capacity, and the associated energy production from these units, was added by state or province. Since wind is the most prominent technology, its projected development is specifically noted.

Figure 2-7: Installed Renewable Capacity by State and Province Year 2017 (MW)

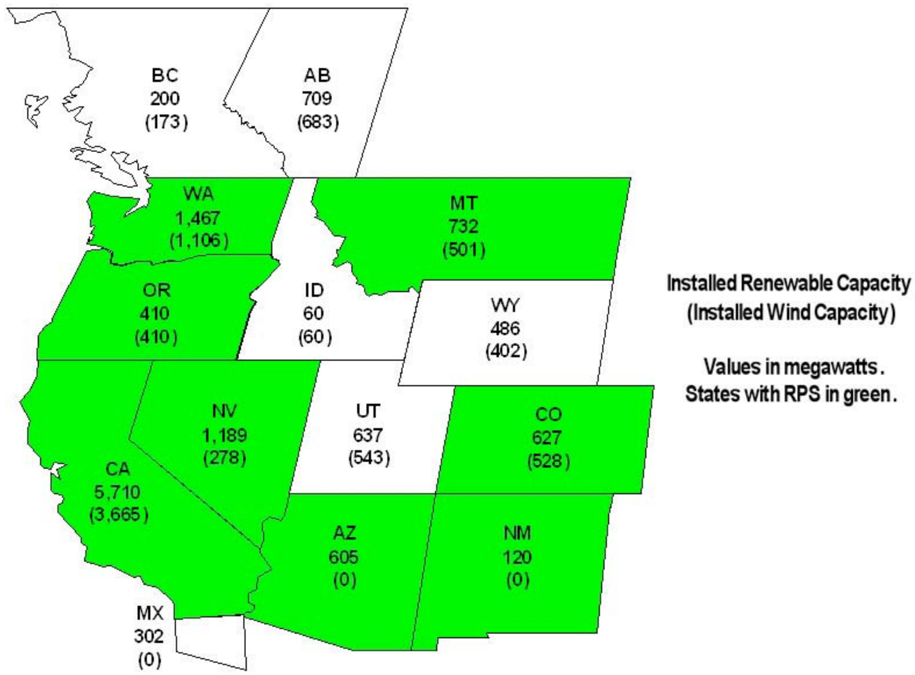
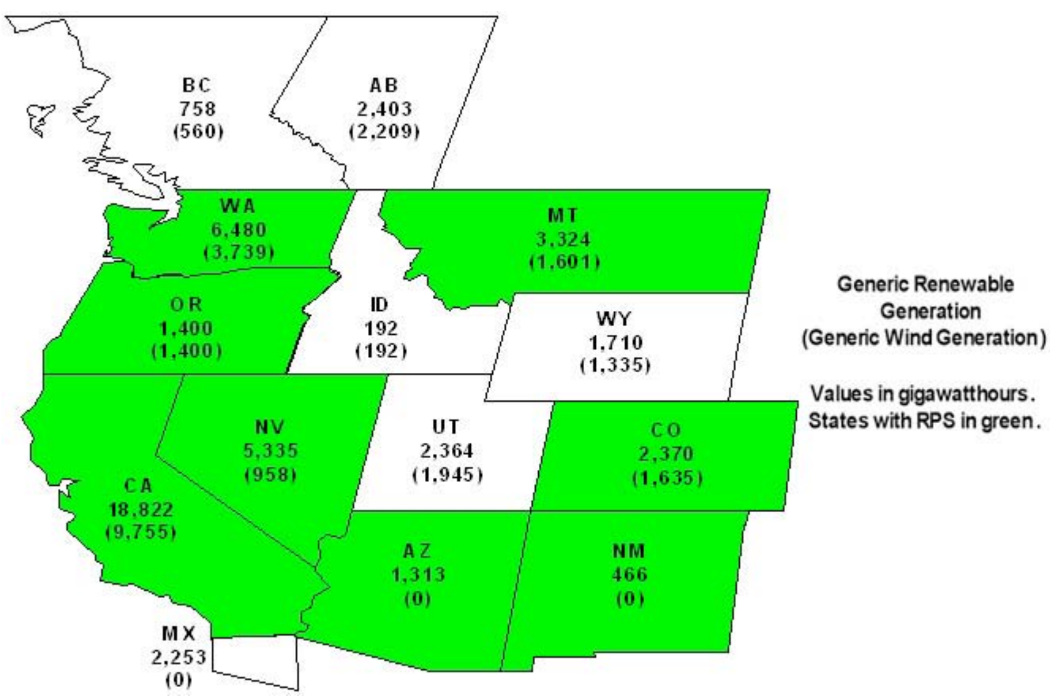


Figure 2-8: Expected Generic Renewable Generation Year 2017 (GWh)



2.3.4 Non-Preferred Resources

The generic resources assumed to be added in the Case 1 resource plan to satisfy a simplified version of resource adequacy requirements are removed in Case 1B to the extent they are not needed given the expected performance of the preferred resource additions. Incremental preferred resources are substituted for generic non-preferred resources to the extent the dependable capacity of such resources properly substitute for some of the generic additions. The net result in California is that some, but not all, of the generic fossil resource additions are removed.

2.3.5 Transmission Additions

Transmission in Case 1B expands from that appropriate for Case 1 because of the need to support renewable generation development. Controversy over how to pay for expansion of transmission into the Tehachipi area of Southern California illustrates the need to develop new bulk transmission to support renewable development when the potential for these technologies is far from the existing bulk system. Table 2-3 summarizes the increases in inter-regional transmission capacity assumed in Case 1B.

Table 2-3: Case 1B Transmission Capacity Additions

From Area	To Area	Year	Transfer Capacity Increase (MW)
Alberta S	Montana	2008	300
Arizona	So. Nevada	2009	1,430
BC	Northwest	2009	500
IID	SCE	2009	1,000
Wyoming	Idaho	2010	700
Imperial	SDG&E	2010	1,150
Montana	Northwest	2011	500
Wyoming	Utah	2011	500
Wyoming	Idaho	2012	800
Montana	Northwest	2013	500
Wyoming	Utah	2013	500
Alberta S	Montana	2014	500
Alberta S	BC	2016	500

2.4 Case 2 – Resource Plans Motivated by Sustained High Fuel Prices

Case 2 is intended to modify Case 1's selection of new resource additions through the influence of extremely high, sustained natural gas and related fuel prices. The prices were prepared by Global Energy using a theme of sustained scarcity pricing embodying high world oil prices and shortfalls of natural gas production in North America. Cost of generating technology capital and operating costs combine with fuel prices to influence the selection of new resource additions in an approximation to "least cost" utility planning.. Unlike short-term "shock" sensitivity analyses that test the effect of a one-year fuel price spike, this analysis reflects long-term fuel cost changes which require some time for the market to acknowledge as sustained and pervasive. This case then evaluates two basic factors: the discretionary changes that suppliers/LSEs would be expected to make in new additions facing such sustained high fuel costs, and the cost of production of existing generating units and those assumed discretionary resource additions installed in the face of these significantly higher fuel costs.

Global Energy developed a sustained natural gas price averaging $10/mmbtu. Appendix H-3 provides a description of the method and results.

Table 2-4 provides the fixed and variable costs of candidate technologies in energy units ($/MWh). Variable consists of fuel cost and variable operations and maintenance (VOM). The purpose of Table 2-4 is to compare levelized cost of energy from various technologies as natural gas prices shift from the basecase level (about $6/mmbtu) to the sustained scarcity pricing level (about $10/mmbtu). The table shows that wind, biomass and geothermal become even less expensive than natural gas combined cycle, but coal increases its margin compared to its principle substitutes. The information on Table 2-4 was used as a rough rule of thumb for the cost differential resource technologies to consider how to revise the resource plan. In addition to the natural gas price, coal prices were also assumed to increase commensurately (i.e. by re-running the coal price model and including the higher natural gas prices as an input to the model).

By inspection of Table 2-4, it is clear that pulverized coal expands levelized cost differential compared to gas-fired combined cycle, and would continue to be a preferable base load resource. Therefore, Case 1 assumptions for some generic combined cycle additions were modified as follows:

- In Alberta: removed 490 Combined Cycle gas generation in 2017/2018 and replaced this with 500 MW of pulverized coal in 2017.
- In N Baja: replace 245 MW of Combined Cycle in 2019 with generic geothermal.

Gas fired peaking units are providing a highly reliable source of power to be called upon infrequently when high load and unit outages are occurring at the same time. Because the peaking gas turbines are not expected to operate often, the higher price of natural gas would not have a material impact on the decision to build the peaking units. Therefore, this study assumes that renewables will not replace these peaking units even when gas prices are high.

Table 2-4: Alternative Resource Costs Under a Sustained Scarcity Pricing of Natural Gas

		Fuel Price Projections			
		$6/mmbtu		$10/mmbtu	
Technology	Fixed Costs	Fuel+VOM	Full Cost	Fuel+VOM	Full Cost
	($/MWh)		($/MWh)		($/MWh)
Pulverized Coal	41.40	11.8	53.2	13.8	55.2
Sequestered Coal	61.46	18.3	79.8	20.3	81.8
Combined Cycle	17.72	44.4	62.1	72.4	90.1
Gas Turbine	197.97	64.3	262.3	104.3	302.3
Wind in Calif	69.24	5.5	74.7	5.5	74.7
Wind in RofW	69.23	5.5	74.7	5.5	74.7
Solar Parabolic	145.00	1.4	146.4	1.4	146.4
Biomass	49.51	11.0	60.6	11.0	60.6
Geothermal Binary	44.93	21.8	66.7	21.8	66.7

Source: Global Energy

Table 2-4 does not include energy efficiency, but under these high gas prices, it is assumed that energy efficiency will be much more attractive. Therefore the following changes to energy efficiency levels assumed in Case 1 were made to construct Case 2:

- For California, energy efficiency is increased to the level assumed in Case 3A.
- For rest of WECC, energy efficiency is 5 percent more than in Case 1 (as opposed to the 11 percent more assumed in Case 3B).

When increasing energy efficiency in the various transareas, gas turbine capacity was reduced in an amount reflective of the lower load levels that will exist on the peak hours when the energy efficiency is increased.

2.5 Case 3A – High Energy Efficiency in California

Case 3A is intended to reflect a major policy initiative to increase California energy efficiency beyond that reflected in current regulatory and statutory requirements. It is built upon Case 1B and adds significantly more energy efficiency and small amounts of demand response (peak shaving) resources beyond those assumed in Case 1B. The higher levels of EE and DR are treated as resources, and they do not reduce the total amount or type of resources needed to satisfy resource adequacy; rather, they are considered as a means of satisfying those requirements.

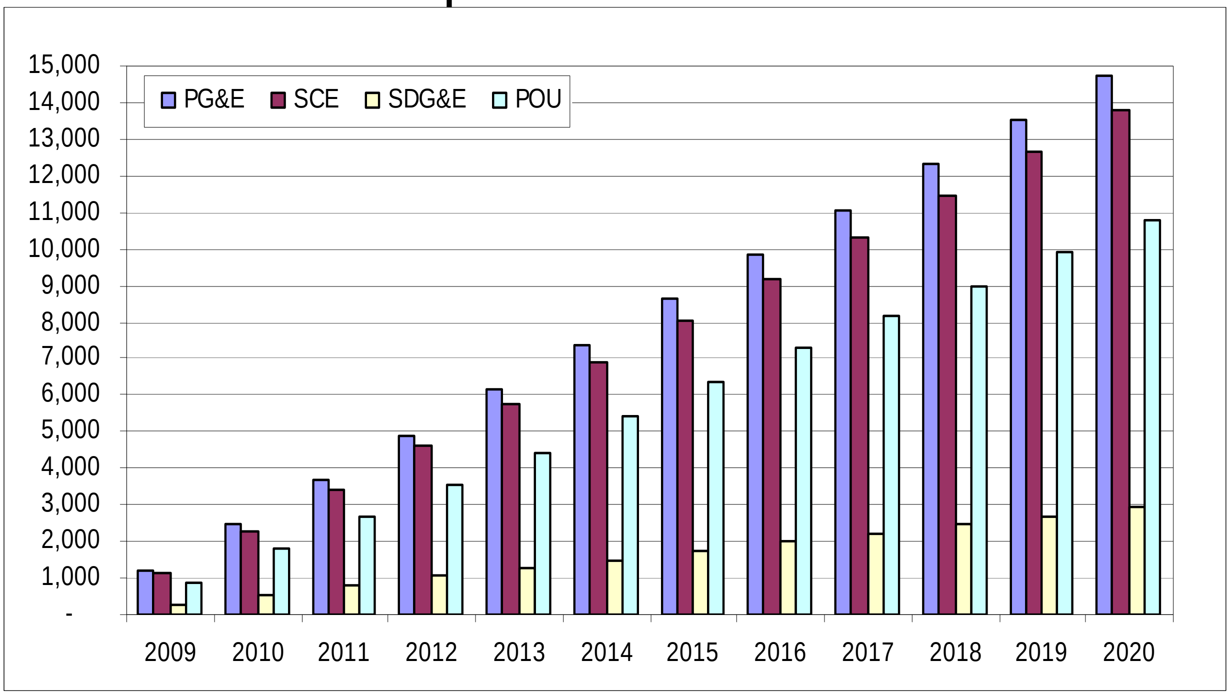
The EE levels were developed based upon the 2006 EE potential study[5]. This study identified the economic potential, that is, the savings that could be realized if all cost-effective EE measures were implemented. Approximately 20 percent of the economic potential comes from emerging technologies. Since there is considerable risk and uncertainty about the actual savings and pace of commercialization of emerging technologies, the EE resource was assumed to be equal to the Economic Potential minus the savings due to emerging technologies. This results in an additional 9,319 GWh (42 percent) of energy efficiency relative to Case 1 for the California IOUs. This same 42 percent increase was applied to the POUs. More detailed data and description of the assumptions are included in Appendix F.

The cumulative EE savings for each IOU and the POUs by year are summarized in Figure 2-9. The net effect of these EE savings is that there is virtually no growth in California retail loads as illustrated in Figure 2-10.

DR increases by 700 MW (20 percent) relative to Case 1 to approximately 4,000 MW as summarized in Figure 2-11. This increased DR capability is based on assuming that PG&E develops DR equal to 6 percent of its load, SDG&E and SMUD develop DR equal to 5 percent of their load, and LADWP develops DR equal to 3 percent of its load. The SCE demand response capability in Case 1 is already at 7.4 percent of its load, higher than any utility or region in the country. Thus, no additional capability was assumed for SCE for Case 3.

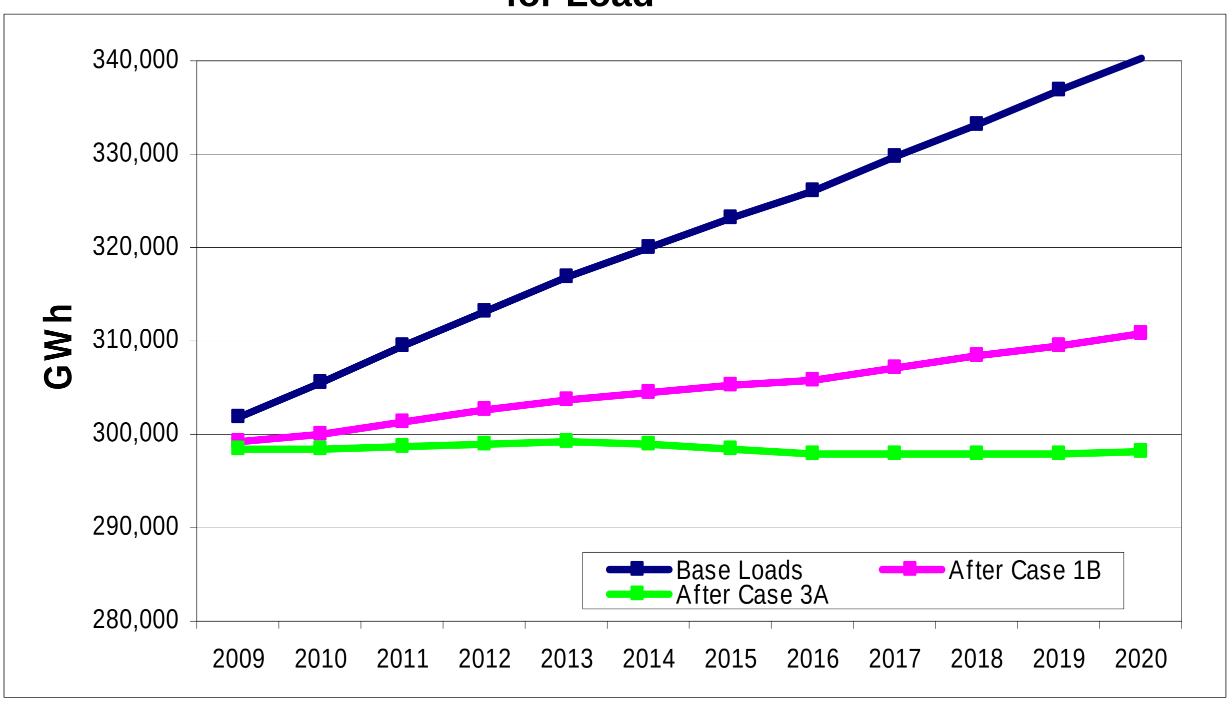
[5] Itron, et. al., op .cit.

Figure 2-9: Projected Cumulative Energy Efficiency Impacts for Case 3A



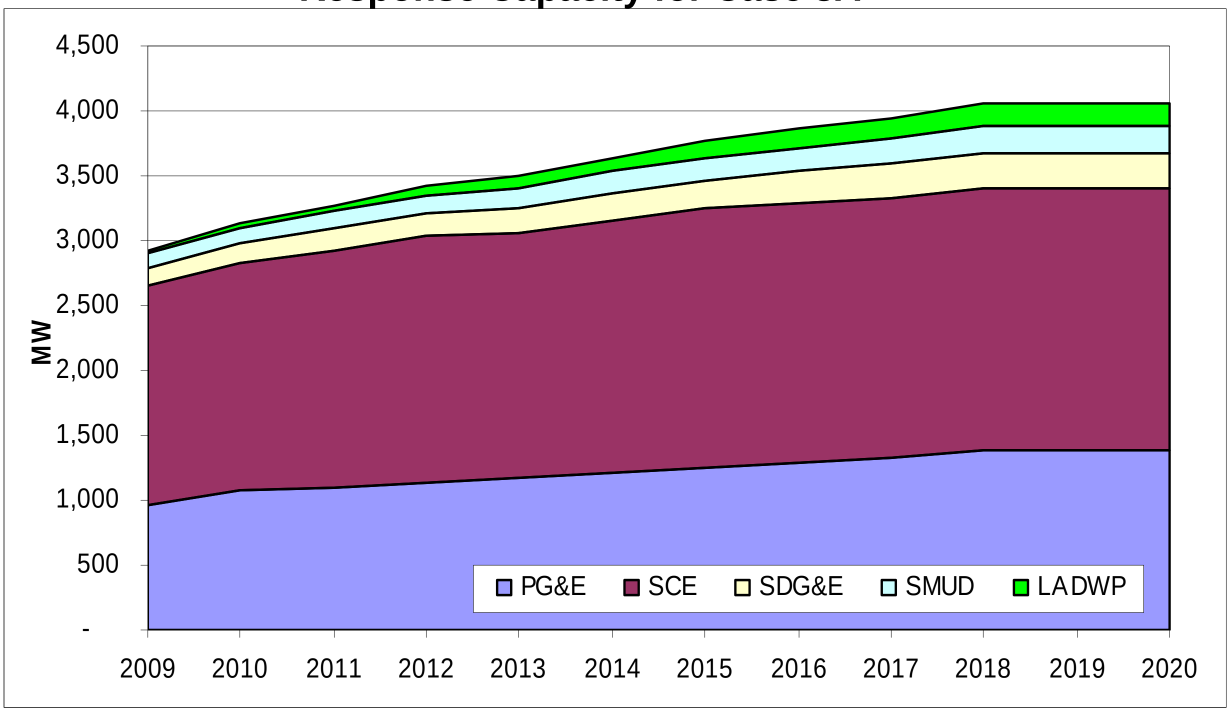
Source: Navigant Consulting

Figure 2-10: Projected Cumulative Impacts on Net Energy for Load



Source: Navigant Consulting

Figure 2-11: Projected Cumulative California Demand Response Capacity for Case 3A



Source: Navigant Consulting2.6 Case 3B – High Energy Efficiency West-Wide

2.6 Case 3B – High Energy Efficiency West-Wide

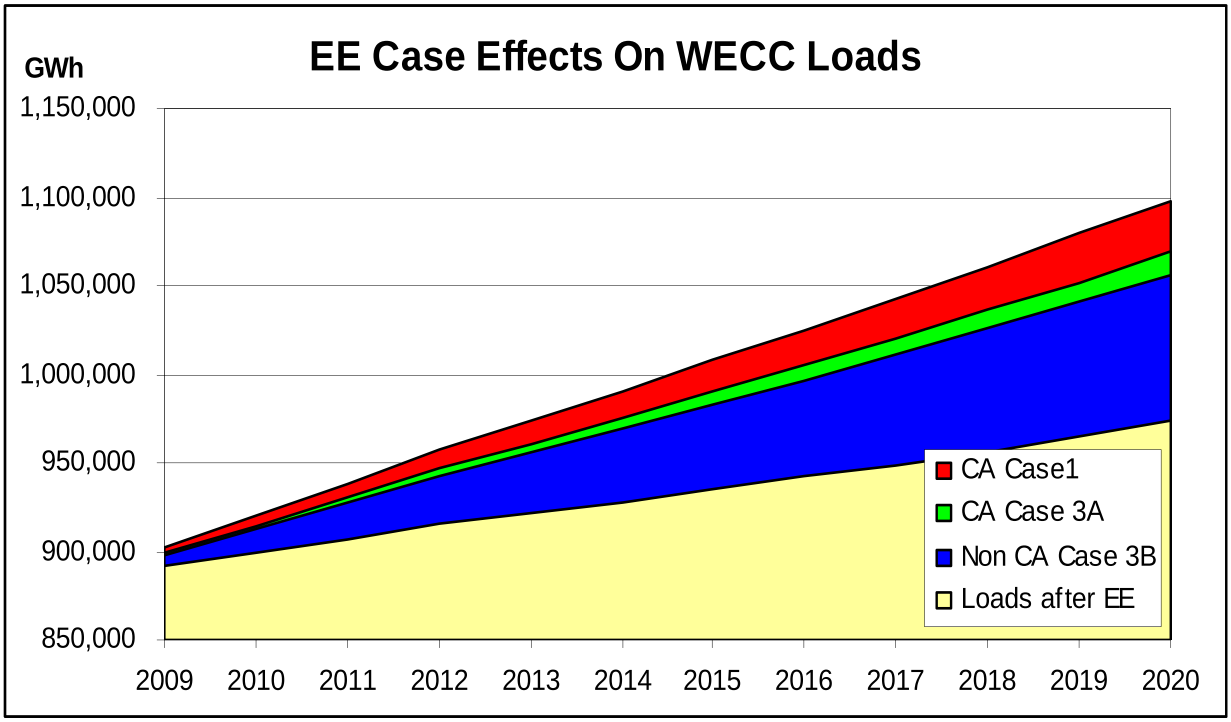
Case 3B extends Case 3A from California to the rest of WECC. Each of transareas in Rest-of-WECC are assumed to achieve 10.9 percent reduction from the basecase 2020 loads assumed in this study. A straight ramp up to this level of impact starts in 2012 and concludes by 2020. The CDEAC process sponsored by the Western Governors Association[6] concluded that 20 percent reduction of loads was feasible. Some interpretation of the CDEAC recommendation has been necessary.

This study interprets the 20 percent goal as applying to a level of energy "requirements" that is already being influenced by utility programs and some standards and codes. This study assumes that implementing best practice energy efficiency programs and practices would reduce electricity requirements by an additional 10.9 percent relative to current programs, meaning that existing programs, standards and codes are already reducing "requirements" by about 9.1 percent. As noted earlier in Section 2.3, an LBL study finds other levels of energy efficiency programs embedded in resource plans available through integrated resource plan filings. For those utilities disclosing sufficient information, "pre-plan" energy efficiency program impacts appear to be closer to 5 percent of load, which would imply a remaining 15 percent reduction if the WGA energy efficiency goal is to be interpreted as a 20 percent reduction from total "end-user energy requirements." The disparity between these two sources of information about Rest-of-WECC energy efficiency program impacts could be improved upon with better information reporting by utilities to some central entity, such as WECC or to WIEB/CREPC, which could in turn make such information available to analysts.

Comparing these alternative assumptions can give a sense of scale. The California energy efficiency included in Case 1B is 8.6 percent of load, and the corresponding assumption for Case 3A is a further increment of 3.8 percent for a total of 12.4 percent (all references to 2020 loads). As shown in Figure 2-12, total WECC load after energy efficiency adjustments grows moderately from 860 thousand GWh in 2009 to 973 thousand GWh in 2020 (an average annual growth rate of approximately 0.8 percent per year). Virtually all of this load growth occurs outside of California. As in Case 3A, this meaningful increase in energy efficiency reduces the assumed peak load significantly, reducing the need for conventional generating resource additions otherwise assumed to be added in Case 1B outside of California.

[6] Western Governor's Association, January 2006, "*Clean and Diversified Energy Initiative: Energy Efficiency Task Force Report*."

Figure 2-12: Impacts of High Energy Efficiency in Total WECC Net Loads for Case 3B



Source: Navigant Consulting

2.7 Case 4A – High Renewables in California

Case 4A is intended to examine a major policy initiative to increase California reliance upon renewable generating technologies. Just as Case 3A builds upon the energy efficiency levels of Case 1B, Case 4A builds upon the renewable generation levels assumed in Case 1B. Both rooftop solar PV and supply-side generating technology levels are increased, especially contributions from wind, geothermal, concentrating solar, and biomass projects. This limited portfolio of renewable resource addition types is not intended to imply that other options are not viable. These four seem mature enough to warrant specific inclusion in the study. Other renewable resources could also be considered, but were not due to study limitations in time and budget.

In this case, higher levels of rooftop PV installations by utility customers were projected through assumed increases in state incentives and new business models for PV packaging and financing. The details of the methodology used is described in more detail in Appendix G. Market penetration in each of the residential and commercial utility customer classes were estimated, by county within California for years 2006, 2010 and 2016. Commercial customers are expected to have a higher penetration of PV installation than residential customers. By 2016, for commercial customers these penetrations are estimated to range from less than 0.5 percent penetration in low utility rate, lower income, and lower technical PV potential counties to over 4 percent in the higher utility rate, higher income, and higher technical potential counties. Average statewide PV penetration under this higher case by 2015 is expected to be less than 1 percent for residential and nearly 2 percent for commercial customers.

The supply-side renewable generating technology portion of Case 4A makes use of four technologies. Table 2-5 provides the year 2020 target capacity for these four technologies and shows the transareas in which these incremental additions were located.

Table 2-5: Resource Additions to Satisfy a High Renewables Resource Mix by 2020

Resource Type	Transmission Area	Installed Capacity (MW)
Geothermal	IID	1,526
	SCE	264
	PG&E	625
	Total	2,415
Solar (CSP)	IID	450
	Imperial Valley	500
	SDG&E	100
	SCE	1,350
	LADWP	0
	PG&E	300
	Total	2,700
Wind	IID	0
	Imperial Valley	600
	SDG&E	500
	SCE	6,702
	LADWP	200
	PG&E	2,136
	Total	10,138
Wood/ Wood Waste	IID	40
	SDG&E	219
	SCE	235
	PG&E	497
	Total	991
Total All Resources, All Locations		16,244

Source: Navigant Consulting

Case 4A resource additions are drawn from the 33 percent by 2020 renewable penetration assumed in a PIER research study called the Intermittency Analysis Project (IAP). Some of the products of the IAP effort have been documented in research reports. [7] Other aspects of the study were obtained from the project team. This study also makes use of the locational elements of the IAP effort. There are numerous detailed differences between the assumptions of the IAP effort and this study, so Case 4A should be thought of as a high renewables case rather than a 33 percent RPS case. There was no effort to exactly determine the capacity needed to satisfy 33 percent RPS annual energy requirement in 2020.

The renewable additions in Case 4A amount to approximately 11,000 MW of dependable capacity in California by the year 2020, which displaces the amount of fossil generation needed in future years. In an attempt to maintain only those resources needed to satisfy prudent planning requirements, generic fossil generation were removed to account for the increase in Case 4A renewable additions, but only 3,000 MW (dependable) generics were available in Case 1B to be removed. Since there is more renewable generation being added than fossil generation available to be removed, the planning reserve margin is higher in Case 4A than in Case 1B.

To facilitate the delivery of these increased renewable resources within California, the transmission capacity between various transmission areas in the state were increased (above the amounts in Case 1B) as summarized in Table 2-6. The transmission capacity increase between the Imperial Irrigation District (IID) and Southern California Edison (SCE) Transmission Areas also required that additional transmission facilities be developed within the IID Area itself. In addition, the development of significant amounts of renewable resources in the High Desert area northeast of the Los Angeles area would likely require modifications (such as looping the Mohave-Lugo 500-kV line into the Pisgah Substation) to the transmission system in the area. These transmission additions would be undertaken primarily to deliver new geothermal energy resources from the Imperial Valley area to SCE and Los Angeles Department of Water & Power (LADWP).

[7] CEC, January 2007, *Intermittency Analysis Project: Summary of Preliminary Results for the 2006 Base and 2010 Tehachipi Cases*, CEC-500-2—7-2009.

Table 2-6: Case 4A Transmission Capacity Additions Imperial Valley to North Gila Substation

	To Area	Year	Increase in Transfer Capacity (MW)
IID	SCE	2015	500
SCE	LADWP	2015	500
IID	IV-NG*	2015	700

Source: Navigant Consulting
*Imperial Valley-North Gila Substation

2.8 Case 4B – High Renewables West-Wide

Case 4B extends Case 4A from California to the rest of WECC necessitating a source of renewable generating potential for this broad region. A noted more fully in Chapter 4, Section 4.4, the CDEAC process was responsive to the original WGA objective to identify 30,000 MW of renewable capacity, so this was a source for supply-side renewable generating technologies. Since rooftop solar PV is important in California, and there are also programs supporting it in Arizona and Nevada, additional rooftop PV penetrations were considered as well.

Case 4B was defined to include higher rooftop PV penetration for the rest of the WECC outside of California – specifically in Arizona and Nevada due to state programs promoting solar energy development. Based on a study performed by Navigant Consulting for the Arizona Department of Commerce[8], if new State incentives and efforts to further promote rooftop PV were undertaken, approximately 45 MW of installed capacity would be in place by 2015 and approximately 250 MW by 2020. Nevada PV additions, under potential aggressive state incentives and programs of a similar nature, were assumed to achieve an equal increase as was assumed for Arizona resulting from the Arizona Department of Commerce study. Thus, for Nevada this means 250 MW of installed capacity in 2015 and 450 MW in 2020. In both locales, dependable capacity across the onpeak period of the day is about 60 percent of nameplate.

The levels of renewables identified in the CDEAC report were used as a foundation for 2020 renewable targets for Case 4B. As a general rule, the CDEAC renewable values were used in creating the 2020 renewable capacity targets for the rest of WECC in Case 4B. While this was the general rule, there were adjustments that were made to the

[8] The *Solar Electric Roadmap Study*, prepared by Navigant Consulting for the Arizona Department of Commerce in October 2006 identified additional state level incentives to those that are primarily now provided by the state's electric utilities to achieve enhanced PV and central station solar development as an employment and economic development interest.

CDEAC renewable numbers due to inconsistencies and time related issues. First, since the CDEAC identified renewables were incremental as of 2004, existing renewables that came online after 2004 were removed from the CDEAC renewable targets. This prevented the double counting of renewable resources that were already captured in the datasets in the production cost model.

Second, there were instances where existing renewable resources in the dataset were inconsistent with CDEAC's renewable targets. As an example, Case 1B included 56 MW of geothermal capacity in New Mexico by 2011; however, the CDEAC report did not identify any geothermal in New Mexico by 2020. In order to stay consistent with the CDEAC renewable capacity totals, in this example, we removed an equivalent amount of wind capacity in New Mexico ensuring that values are equal on an energy basis. While the capacity by renewable resource types are slightly different in Case 4B compared to the CDEAC report, the resulting total renewable energy is comparable even if capacity is different.

Lastly, the CDEAC report identified 2020 renewable targets by state which was not entirely transferable to the transmission areas included in the data model. Consequently, it was necessary to divide the CDEAC states into the transareas modeled in this study. For example, in Global Energy's production cost model, Nevada is modeled as two transareas; Northern Nevada and Southern Nevada. However, the CDEAC report identifies renewables for the entire state of Nevada. In these instances, judgment was made as to where the potential renewable resource would most likely be built based on knowledge of existing and potential renewable resource additions in specific geographic regions. Following our example for the state of Nevada, it was estimated based on recent wind development news that two-thirds of the CDEAC identified wind capacity would be allocated to Northern Nevada, while one-third would be allocated to Southern Nevada. Clearly subjective information enters the analysis.

After these adjustments to the CDEAC starting point, Case 4B includes approximately 16,000 MW more of nameplate renewable capacity in the rest of WECC in the year 2020 compared to Case 1B. Table 2-7 summarizes the total incremental renewable capacity used for the Rest-of-WECC in Case 4B for the year 2020. Since the renewable build-out for Case 1B and Case 4B are based on independent studies, there are occurrences where there was a particular amount of renewable resource type in Case 1B that is non-existent or a smaller amount in Case 4B.[9] Under these circumstances, a negative number appears in the table.

[9] Case 1B renewable buildout was prepared by Energy Commission staff as described in Section 2.3.3 of this chapter. Case 4B renewable buildout was prepared by the Scenario Project team as described in Chapter 4, Section 4.4, and this section.

Table 2-7 Incremental Renewable Capacity for Rest-of-WECC in Case 4B

Transarea	**Total Incremental Installed Capacity (MW)**				
	Wind	**Biomass**	**Geo**	**Solar (CSP)**	**Total**
Northwest	1800	0	0	717	2517
Montana	-180	-30	-8	92	-126
Idaho	-46	726	760	0	1441
Wyoming	816	-134	0	0	682
Nevada	646	0	507	318	1471
Colorado	5789	0	-19	129	5899
Utah	-87	-150	0	0	-237
New Mexico	-258	0	190	-36	-104
Arizona	4458	-27	0	-36	4395
Total	12939	385	1430	1184	15938

Source: Energy Commission Scenario Project

The renewable resources in Case 4B amount to approximately 22,000 MW (dependable) throughout the WECC by the year 2020, which should displaces the amount of fossil generation needed in future years. In an attempt to maintain only those resources needed to satisfy prudent planning requirements, generic fossil generation were removed to account for the increase in Case 4B renewable additions, but only 14,000 MW (dependable) generics were available in Case 1B to be removed. Since there is more renewable generation being added than fossil generation available to be removed, the planning reserve margin is higher in Case 4B than in Case 1B.

To facilitate the delivery of these increased renewable resources within WECC, the transmission capacity between various transmission areas in WECC were increased (above the amounts in Case 4A) as summarized in Table 2-8.

Table 2-8: Case 4B Transmission Capacity Additions

From Area	To Area	Year	Increase in Transfer Capacity (MW)
Wyoming	Utah	2013	1,200
Northwest	Idaho	2015	500
Wyoming	Colorado (E)	2015	500
Wyoming	Colorado (W)	2017	500
New Mexico	Arizona	2018	1,600
Idaho	No. Nevada	2018	500
Montana	Wyoming	2018	500

2.9 Case 5A – High Efficiency and High Renewables in California

Case 5A combines the high efficiency assumptions of Case 3A and the high renewables assumptions of Case 4A into a single case. Thus, the PROSYM dataset created for Case 4A, which included numerous facility additions and changes in transfer capacity between transareas, was modified to include the incremental energy efficiency assumptions of Case 3A. For purposes of this analysis, the input assumptions of the two different cases were combined.

Unlike the treatment that existing RPS laws would have allowed, the level of renewables modeled in Case 5A were not reduced for the effect of lower customer purchases of electric energy resulting from the Case 3A energy efficiency assumptions.[10] This approach did create excess resources, as measured by the resource adequacy guidelines followed for each case of this study, even though all generic thermal resources added in the original Case 1 dataset had already been eliminated in previous cases. Thus, no resources were removed when the energy efficiency assumptions of Case 3A was increased in California in Case 5A relative to the lower levels that were included in Case 4A. This means that the reserve margins for this Case grow above the minimum 15 to 17 percent target planning reserve margin used to ensure that the resource plans are likely to satisfy reliability criteria. (See Chapter 6 for supply/demand capacity tables.)

2.10 Case 5B – High Efficiency and Renewables West-Wide

Case 5B combines the high levels of efficiency of Case 3B and high levels of renewables of Case 4B. Like Case 5A, Case 5B is virtually a direct summation of the input assumptions of these two separate cases. The dataset for Case 4B was the starting point for the analysis, and the efficiency levels of Case 3B were added to the dataset to construct the initial version of the Case 5B dataset. When the higher energy efficiency levels are added in this case for areas outside of California, there was an attempt to remove generic resources in order to maintain the target 15 to 17 percent planning reserve margin. In some areas there were not enough generic resource additions still present from earlier cases to remove, therefore those areas experienced an increase in reserve margins above the target level. In other areas, we were able to remove generic new resources in sufficient quantity to maintain the same reserve margin when the energy efficiency was increased from the levels previously included in the original Case 4B dataset to those higher levels from the Case 3B dataset.

To facilitate the delivery of the renewable resources within the total Western Interconnection with lower loads (after energy efficiency was accounted for and some generic fossil resources were removed), the transmission capacity between two

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[10] Renewable portfolio standards are generally defined in terms of annual energy, and this energy is further defined to be sales to end-users. Thus, the greater the effects of energy efficiency programs and measures, the less absolute value level of renewables needed to be.

transmission areas was increased (above the amounts in Case 4B) as summarized in Table 2-9.

Table 2-9: Case 5B Transmission Capacity Additions

From Area	To Area	Year	Increase in Transfer Capacity (MW)
New Mexico	Arizona	2013	900
Wyoming	Utah	2015	500

CHAPTER 3: METRICS FOR MEASURING RESULTS OF THE ANALYSES

The overall project is intended to examine the implications of high energy efficiency and high renewable generating technology penetrations that are likely to be needed in order for the electricity sector to achieve the green house gas emission reductions set forth for California in AB 32. These implications encompass GHG reductions, changes in the resource mix and energy produced by various technologies, possible changes in reliability, costs to electricity consumers, and traditional environmental measures. Following a very brief description of each of these perspectives from which the results will be evaluated, the balance of this chapter provides more detail for each of the metrics that describe the results.

The GHG reductions are almost entirely associated with displacing dispatch of existing fossil power plants or deferring or avoiding the construction of conventional generating technologies. The characterization of GHG emissions is limited to carbon as opposed to a much larger suite of GHGs that might be addressed in studies of industrial facilities.

The energy system metrics used to describe the results include capacity by generating technology and the predicted electricity production for each technology. While the PROSYM model operates on an hourly basis for the entire period 2009 through 2020, this report focuses exclusively on annual measures of electricity production. Since PROSYM operates on a zonal basis (each zone is called a transarea in this report), this creatres a large volume of geographic detail. Generally the main report focuses upon California and the aggregation of all non-California transareas (Rest-of-WECC).

Electricity costs and the impact they would have on consumer rates is measured in two ways. First, electricity production costs provide a measure of all of the variables costs going into the production of a unit of electrical energy. Since capital investment is an important additional element of total costs, this study computes the differences of each of the cases numbered 1B and higher compared to Case 1. This measure of capital costs allows each of the cases to be compared to each other, but by leaving out an assessment of the capital costs of generating facilities and transmission investment of all of the elements that do not change from one case to another, the total impact on rates is difficult to interpret.

Criteria pollutants like NOx and SOx, toxic pollutants like Mercury (Hg), and water consumption are some of the more important means of describing the environmental footprint of electricity generation on the overall environment. Of course there are other measures that create great controversy, but these few have been difficult enough to quantify within the resources of this study.

Sections 3.1 through 3.5 will review each of these topics in greater detail.

3.1 Greenhouse Gases

As used in this report, GHG is synonymous with carbon. No other GHG constituents were assessed. For California, GHG emissions include emissions from operating plants located in California, operation of plants outside of California whose output is intended to meet California load (largely reflected in ownership shares of specific facilities), and GHG attributable to spot market purchases that California is making, which in the model displace higher cost California resources. Treatment of this last category is controversial and is inherently imprecise in a forecasting mode when no specific contracts or spot market purchase records exist to guide attribution.

Global Energy developed a method to compute annual average GHG emissions for "imports" that uses the annual average characteristics for all Rest-of-WECC generation. This method was compared to a similar method that uses simple annual averages for imports coming from two subregions of Rest-of-WECC into California. The Energy Commission uses such a two-source method in its annual Net System Power (NSP) report.[11] The method developed by Global segregates "remote" generators from other sources of power imported into California.[12] Thus the Global method is more precise in its characterization of emissions from "remote" generators, but les precise that the NSP method for the residual amount of imports that cannot be directly attributed to a specific facility.

Table 3-1 describes the Global method developed for this study. To test whether the loss of specificity by using a one-source method for residual imports or the two-source method produce significantly different results, Global computed emissions for year 2020 using both methods. The two were within four percent of each other. In light of the test results, the simpler, one-source method was used for this study. Thus, California GHG responsibility is computed in three parts:

- Instate generation with power plant specific emission factors,
- Remote generation with power plant specific emission factors, and
- Imported generation computing annual average emissions in the same proportions as the annual average for Rest-of-WECC carbon emissions.

[11] The Net System Power report is adopted by the Energy Commission each year. It is used by utilities to describe the nature of power purchases in satisfaction of statutory mandates to provide power system labeling information to customers.
[12] Remote generators are those facilities located outside of California that are owned by or under long term contract to California LSEs. (See Chapter 5 for a listing of these facilities.)

Table 3-1: Projection of California Responsibility for Carbon Emissions*

Major Element	Secondary Element	Approach
Instate Generation	NA	Compute emissions directly on plant by plant basis using plant-specific emission factor
Remote Generation	NA	Compute emissions directly on plant by plant basis using plant-specific emission factor, and allocate California share to California and debit California share from Rest-of-WECC
Imports	Northwest	Determine Northwest source for California imports using PROSYM exchanges between transareas for each calendar year Apply annual average carbon emission of Northwest powerplants to California's imports from the Northwest
	Southwest	Determine Southwest source for California imports using PROSYM exchanges between transareas for each calendar year Apply annual average carbon emission of Southwest powerplants to California's imports from the Southwest

Note: All non-carbon GHG emissions are not quantified.

3.2 Energy Measures

Since this study is a comparison of built out and operated electricity resource plans, the typical measures of associated with this industry have been used. These include: (1) capacity of various generating technology types – both installed capacity and dependable capacity, where dependable capacity is the portion of the installed capacity that can be relied upon to meet peak load requirements, (2) energy produced by each generating technology type, (3) fuel used by various generating technology types, (4) differential capital cost relative to Case 1, and (5) incremental operating costs relative to a base year.

Table 3-2 summarizes the various measures available for specific resource types (both demand side and generating technologies and/or fuels used) for which results are reported. These values are almost always used in the conventional manner.

Dependable capacity was used for purposes of imposing a simplified version of resource adequacy on all transareas when the resource mix was being established. For supply-side generating technologies that operate intermittently without backup storage, such as wind and central solar, dependable capacity was computed using a procedure similar to that established by California's resource adequacy protocols for net qualifying capacity. Historic production data or solar insolation data were processed to determine average production in the time period corresponding to peak demand. For summer peaking regions this was Noon to 6PM, while for winter peaking regions it was 4AM to 10PM. This results in major reductions from installed capacity for resource adequacy purposes. Appendix E-1 provides greater detail about the special manner in which dependable capacity was computed.

Energy efficiency was provided 15 percent additional credit in resource adequacy computations to reflect the fact that once in operation this class of resources requires no reserves.

Table 3-2: Energy Measures Reported for Resources

Resource Type	Capacity		Energy	Fuel
	Nameplate	Dependable		
Hydro-Electric	X	No change	Annual	NA
Pumped Storage	X	No change	Annual	NA
Coal	X	No change	Annual	Coal computed using facility heat rates
Combined Cycle	X	No change	Annual	Natural gas computed using facility heat rate
GT	X	No change	Annual	Natural gas computed using facility heat rate
Biomass/Other#	X	No change	Annual	NA
Geothermal	X	No change	Annual	NA
Wind	X	Derated to average onpeak performance using CPUC method	Annual	NA
Energy Efficiency	X	Assumed to perform at 100% of program enrolled capacity	Annual	NA
Rooftop PV	X	Derated to average onpeak performance using CPUC method	Annual	NA
VDR	X	Assumed to perform at 100% of program enrolled capacity	##	NA

- Biomass/Other includes a considerable list of generating technologies and resources that collectively have a small contribution to serving end-user load. California plants include Biomass, Central Solar, Refuse, Wood, Jet Fuel-fired plants, Petroleum Coke-fired plants, and Variable Demand Reduction.

- VDR energy included in Other.

3.3 Electricity Costs

Determining the impacts of the alternative cases on generation costs was an importance measure of this assessment. All of the principal elements of productions costs have been quantified. The fixed costs for generation and transmission resources that have been added in Case 1 and then partially deferred in the other cases designed to show preferred resource additions have been determined. The fixed costs of existing units and named additions coming on line up to 2011 have not been included. Table 3-3 summarizes how various cost components have been treated.

Fixed costs are a big part of many resources, renewable resources in particular. The approach of calculating changes in production costs and changes in fixed costs between cases allows for a comparison of the changes in costs as one moves from one case to another, but does not provide the entire cost of providing the electricity to meet load in WECC and/or California.

The analysis also shows electricity costs through time on a levelized basis. This allows some improvement in comparing between the various cases where the tradeoffs of high fixed cost, low operating cost resources compared to a more conventional set of resource additions through time might be important.

Retail rates reflect revenue requirements needed to recover generation, transmission, distribution, A&G, and other miscellaneous costs. This project deals primarily with generation costs, but does include some incremental transmission costs. As indicated above, the Generation and transmission costs reported do not reflect all the sunk capital costs for existing facilities. What is shown in the data reported for this study is the increment (or decrement) in certain generation and transmission costs that would be experienced in the different cases. It is not possible to indicate how this increment (or decrement) in costs would be assigned to the various customer classes or to different rate blocks of a retail rate.

Table 3-3: Elements of Rates Quantified in Analyses

Rate Component	How Addressed	Implications of Not Being Addressed
Cost of Generation		
Capital		
Ratebase for existing and named additions common to all scenarios	Omitted	Makes comparing cost differences between scenarios to existing rates difficult
Ratebase for generic additions	Included	
Fuel Cost	included	
O&M Cost	included	
Environmental Compliance Costs	Where ongoing expenses exist (for SOx and HG) are included as expenses; where one time costs exist (like NOx offsets) added to ratebase	
Wheeling Charges	Included	
Preferred Resources		
EE Expenses	Included as expenses in year of program addition	
DR Expenses	Included as expenses in year of program addition	
Solar PV Costs	Included as capital cost additions	
Transmission		
Ratebase for existing and committed additions common to all scenarios	Omitted	Makes comparing cost differences between scenarios to existing rates difficult
Ratebase for additions of each case	included	
Distribution and Other Elements of Costs	Not quantified	No change across cases means this component of rates can be ignored

3.4 Other Environmental Measures

Other environmental measures included in this study attempt to reflect the implications of alternative resource plan development and how both existing and new resources might operate through time. As such, the following measures were assessed: (1) NOx emissions by geographic region, (2) SOx emissions by geographic region, (3) mercury released to the atmosphere through coal combustion, and (4) water used in power generation by geographic region. Water usage can be examined using two specific metrics: (1) water used in the combustion process and (2) water diverted from a source for once through cooling and then returned to its source.

The quantities estimated for these metrics are affected by two basic elements of the methodology: (1) by the change in resource mix through time as new resources that are added (or avoided via energy efficiency or renewable resources), which may not have some or any of these negative environmental consequences, and (2) through quantifying the expected levels of operation of all resources, including existing plants, to assess their estimable environmental consequences for these specific emissions and water use.

The quantities of criteria pollutants that are measured are those directly emitted from power plant operation. In some jurisdictions, it has now been decades since environmental protection laws and regulations required some new and existing facilities to offset one or more pollutants. Compliance with these requirements frequently is part of the facility licensing process, although regulations imposing retrofit requirements on existing facilities can also lead to emission reductions. At least some of these initial licensing and ongoing compliance mechanisms reduce or eliminate the environmental consequences of the pollution from a new facility. In effect, a shift in the source of pollution from offsetting facilities to a power plant has taken place. This study does not take any of this offset process into account. The emissions that are reported should be considered “gross” emissions that may in whole, or in part, be offset by emission reductions elsewhere resulting in lower “net” emissions harming the environment.

CHAPTER 4: CHARACTERISTICS OF RESOURCE TYPES

This chapter provides a broad overview of the characteristics of the resource types used to construct the cases. Although both conventional and preferred resource types are important to the analysis, the conventional resources are generally well understood. The preferred resource types are less certain and therefore the specific assumptions used in this study will be discussed in greater detail. Even more detail is provided in various appendices. Ideally one would like a locational "supply curve" for the various efficiency and generation technologies to enable design of several scenarios moving up the "supply curve," but the necessary studies do not exist. This study, therefore, assembled resource characteristics data and assumptions from a wide variety of sources to construct specific scenarios to be evaluated.

This chapter reviews the sources of technology cost data in the initial Section 4.1, and then discusses performance and locational details in a series of sections specific to each kind of technology. Section 4.7 completes this chapter by discussing the transmission implications of adding the various resource types. Energy efficiency and rooftop solar PV tend not to require transmission additions or even to defer those that might have been required with a resource plan build out using conventional technologies, while renewables tend to require special transmission additions due to their locational constraints compared to the more readily sited natural gas-fired technologies.

4.1 Cost of Generation

This study used the Cost of Generation (COG) project undertaken by the Energy Commission staff for the *2007 Integrated Energy Policy Report (IEPR)* as a general source for capital costs for all supply-side resource types. The COG project includes technology characterization analyses funded by the Energy Commission's PIER program, and efforts by the staff itself. That project has documented its results for current costs and presented them in a public workshop. This study used the current cost values existing as of May 1, 2007, that were included in the initial release of results by Energy Commission staff and assumed that they are unchanged through time. The extent of such cost reductions or performance enhancements is uncertain. Clearly proponents of various technologies aspire for cost reductions and performance improvements through time, but the time allowed to and resources available for this project simply did not allow a more complete examination of the implications of these uncertainties.

4.1.1 Supply-Side Renewable Cost of Generation Estimates

Estimates for the installed cost of renewable resources were derived from "instant" 2006 dollar costs for select renewable technologies from a May 2007 draft Energy Commission report – *Comparative Costs of California Central Station Electricity Generation Technologie*s. This report developed costs for a wide variety of renewable energy generation technologies considering typical size, project life and "overnight" or "instant" cost per kW. Sources of data for these costs included:

- Vendor data
- Completed cost of specific projects
- U.S. Department of Energy National Renewable Energy Lab studies
- Research results from various universities
- Energy Commission research or compiled data
- Other public domain studies completed by Navigant Consulting

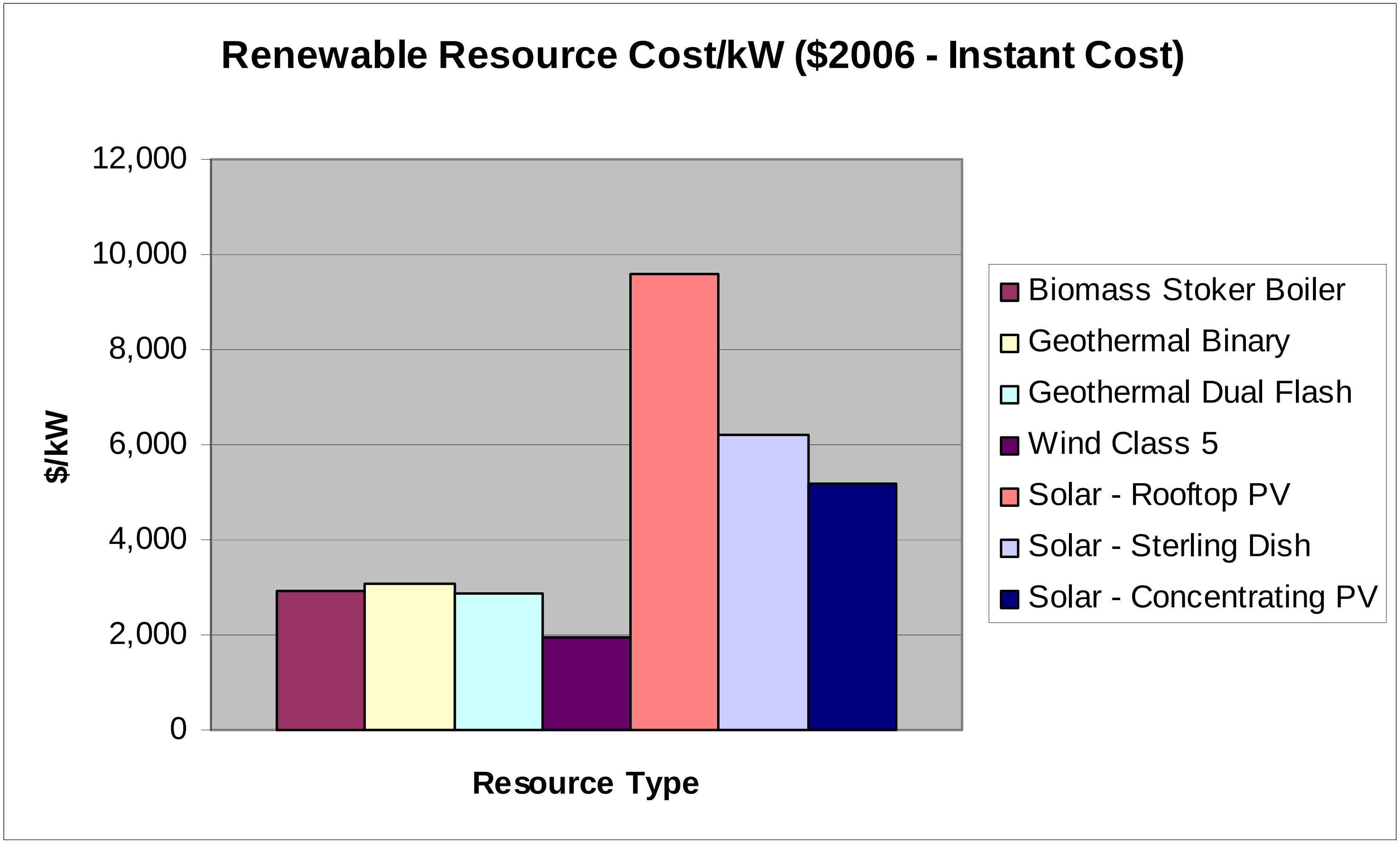
Only select renewable technologies were used in the study. Exclusion of a technology is not necessarily an indication of preference or expected relative viability. Inasmuch as this analysis was limited in term and budget, and resource additions were modeled throughout the U.S. portion of the WECC, those resources which were expected to comprise the largest cumulative addition of capacity during the study horizon, or where specific technology projects were known to be planned in meaningful cumulative capacity, were selected.

Figure 4-1 provides the "instant costs" for the select renewable technologies used in this analysis. These instant costs were then converted into "installed costs" considering factors such as interconnection costs, permitting and development costs, interest during construction, and other cost additions. Those costs were then used by Energy Commission staff in a detailed levelized generation cost model that converted the costs to a total levelized cost per MWh considering annual costs such as debt financing, return on equity, property tax, income taxes, depreciation allowances, fixed O&M and other fixed costs, along with estimated fuel and variable operation and maintenance costs based on typical annual capacity factors. With the exception of rooftop solar PV, all technologies in Figure 4-1 are central technologies. Rooftop solar PV is included in this figure to provide a comparison of relative costs.

4.1.2 End-User Cost of Generation Estimates

End-user technologies (energy efficiency, demand response and rooftop solar PV) are discussed in Sections 4.2, 4.3 and 4.5 of this chapter. As explained in more detail in Section 4.5, the rooftop solar PV costs developed by Navigant Consulting, and shown in Figure 4-1, were replaced with an alternative set of assumptions.

Figure 4-1: Instant Cost of Renewable Technologies (per kW, $2006)



Source: Draft Energy Commission staff report, *Comparative Costs of California Central Station Generation Technologies*, May 2007

4.1.3 Summary of Technology Costs

The estimates of generation technology costs shown in Table 4-1 were derived from several sources. The estimated costs for pulverized coal and IGCC coal generation technologies were derived from cost assumptions developed participants in the Frontier Line Phase II effort. These costs are considered to be the most recent estimates for the relevant technologies for the locations for new fossil-fueled generation resources anticipated during the period of study for this analysis. The costs of other technologies, except rooftop solar PV, were derived from the COG project analysis.

These “instant cost” estimates were then input to the COG levelized cost model to develop estimated levelized cost per kW-year for each technology. Case 1 reflected the building of certain generic coal and gas fired plants. The coal and gas plant levelized fixed costs/kw-year were added for these units in Case 1. If these plants were not included in a later case (e.g. because EE or renewables were build instead), then these fixed costs/kw-year were removed. In place of these costs, the levelized fixed cost/kw-year of the replacement resource was added. The only other use of these costs were to develop a relative ranking of costs to provide input to a decision the likely future resource build portfolio in Case 2 as discussed below.

Since this study uses a production cost model to determine the operating profile of each individual resource added to the resource mix, the annual capacity factor assumptions used in the Energy Commission’s COG project are only relevant for the purposes of constructing a basis for comparing across technologies. Further, this study used its own specific set of fuel price projections rather than those used in the COG project. In effect, it is the capital costs of the various technologies from the COG project that were used in this study.

To allow this study to compare the technologies on a consistent basis for purposes of designing Case 2 (extended high gas prices), Table 4-1 presents a levelized cost per kW-yr for the various technologies, and variable O&M and fuel (where applicable) are added to develop a full cost per MWh estimate for the technologies. Natural gas prices at $6/mmbtu and $10/mmbtu and corresponding modified cost of coal for the gas price cases were used to develop two sets of full cost estimates (using units of $/MWh), which levelizes installed costs. Fixed costs are converted from capacity units of $/KW-yr to energy units of $/MWh based on assumed indicative capacity factors of the resources. The applicable real fuel and variable O&M costs are combined to produce a comparable full cost in units of $/MWhr. Since these nominal fuel costs of $6/mmbtu and $10/mmbtu are assumed constant, they do not modify the levelization consequence of the capital and other fixed costs.

As indicated above, the capital cost values (in $/Kw-yr) in Table 4-1 were used for all cases. The Full Cost (in $/MWh) were only used to help design Case 2 by providing insight into which resources are preferable under significantly different views of possible future gas prices.

Table 4-1: 2006 Levelized Cost Assumptions for Central Station Technologies

Technology	Source	Instant Cost ($/KW)	Indicative Capacity Factor	Calculations CEC Model Fixed ($/KW-yr)	Fixed Energy Costs ($/MWh)	Alternative Fuel Price Projections $6/mmbtu Fuel+VOM ($/MWh)	$6/mmbtu Full Cost ($/MWh)	$10/mmbtu Fuel+VOM ($/MWh)	$10/mmbtu Full Cost ($/MWh)
Pulverized Coal	Frontier Line study	$2,000	83%	302.1	41.40	11.8	53.2	13.8	55.2
Sequestered Coal	Frontier Line study	$2,700	78%	422.1	61.46	18.3	79.8	20.3	81.8
Combined Cycle	CEC COG Study	$901	89%	138.5	17.72	44.4	62.1	72.4	90.1
Gas Turbine	CEC COG Study	$1,058	9%	156.4	197.97	64.3	262.3	104.3	302.3
Wind	CEC COG Study	$1,996	32%	195.2	69.24	5.5	74.7	5.5	74.7
Solar Parabolic	CEC COG Study	$4,174	39%	497.9	145.00	1.4	146.4	1.4	146.4
Biomass (Stoker)	CEC COG Study	$3,230	88%	382.6	49.51	11.0	60.6	11.0	60.6
Geothermal (Binary)	CEC COG Study	$3,498	93%	366.5	44.93	21.8	66.7	21.8	66.7

Source: Energy Commission Staff, Global Energy.

4.2 Energy Efficiency

4.2.1 Energy Efficiency in California

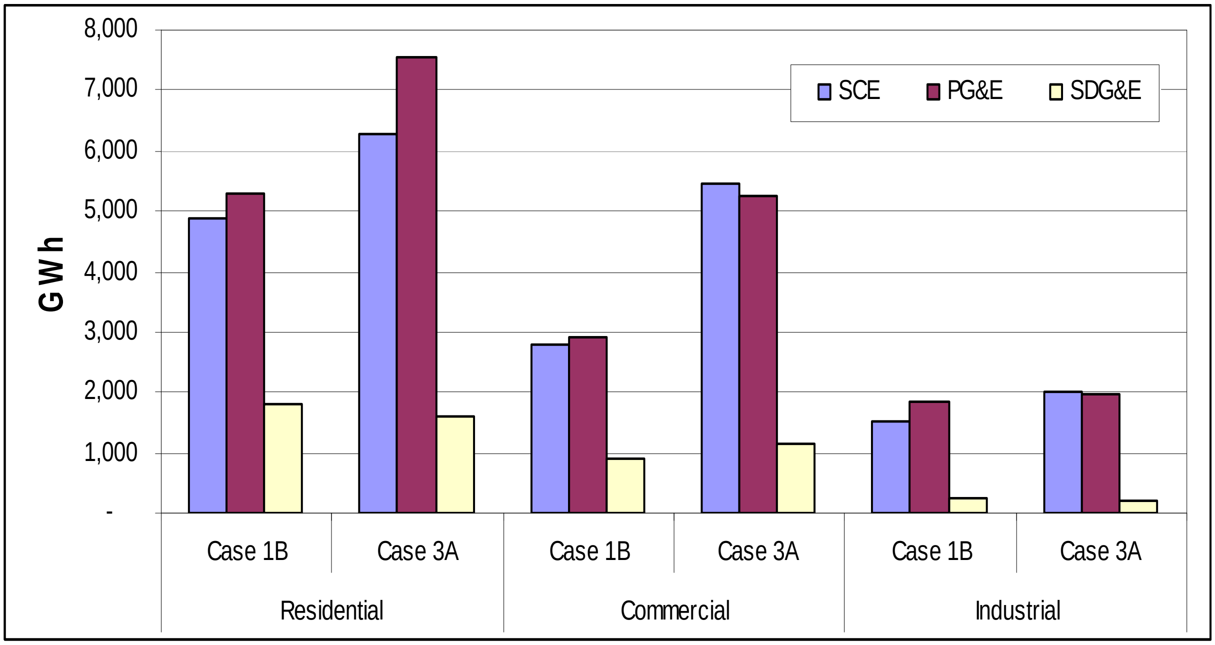
Energy efficiency beyond the programs approved by the CPUC in 2006 for implementation for the period 2006 through 2008 is largely drawn from a study of energy efficiency potential prepared by Itron using 2004 data that became available in 2006. Stereotypically, such studies separately identify technical, economic, and achievable potential. For this study the data for the full incentives (the most aggressive of the achievable potential scenarios) and economic potentials were used. Annual savings by customer segment (new and existing residential, commercial, and industrial) and IOU were developed based on the potentials (full incentives for Case 1B, and economic potential for Case 3B) available in each year. The cumulative savings by IOU and customer segment are summarized in Figure 4-2. Annual savings by customer segment (new and existing residential, commercial, and industrial) and IOU were developed based on the potentials (full incentives for Case 1B, and economic potential for Case 3B) available in each year.[13]

While the residential segment accounts for most of the savings, the commercial sector represents 57 percent of the incremental savings between Case 1B and Case 3A, as shown in Figure 4-3.

Costs for implementing these energy efficiency programs were also obtained from the ITRON study. Total resource costs were used, including both program and measure costs. The average costs by segment, IOU and Case are summarized in Figure 4-4. Energy savings cost the most in the new residential segment and the least in the new industrial segment. Because the ITRON study indicated lower measure costs for some segments for the economic potential than for the full incentives potential, the same measure costs were used for both Cases 1B and 3A. Program costs were assumed to be 20 percent higher per unit of energy saved for Case 3A relative to Case 1B, reflecting the need for more aggressive marketing to obtain the higher penetrations. Overall, costs per kW saved in Case 3A are only 3 percent more than the costs for Case 1B on a total cost per kWh saved basis.

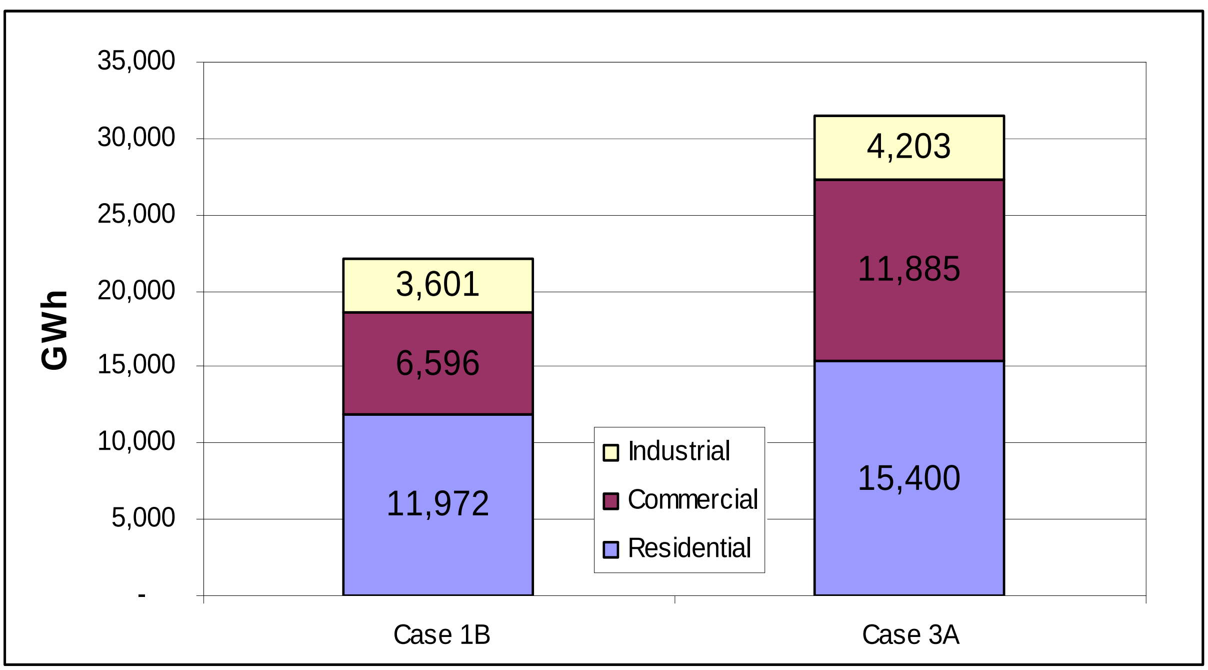
[13] The annual energy efficiency savings for SDG&E are the same in both Cases 1B and 3A, because SDG&E's LTPP goals exceed their economic potential. Because the distribution of savings between the residential, commercial, and industrial sectors are different for the full incentives and economic incentives projections, the Case 3A savings are lower than the Case 1B savings for the residential and commercial sectors, while the commercial savings increase for Case 3A.

Figure 4-2: Cumulative California IOU Energy Efficiency (2009–2020) by Customer Segment and IOU



Source: Navigant Consulting

Figure 4-3: Comparison of the Incremental Energy Efficiency Potential by Customer Segment



Source: Navigant Consulting

This modeling assumes that energy efficiency savings are funded completely (Total Resource Cost) in the year it is accomplished and in this study its costs (both customer costs and portions paid by delivery agents) are recorded in the delivery year. It is also assumed that the energy efficiency measures continue to perform at the same level through the study period (2020).

Because these impacts have to be allocated on an hourly basis for the production cost model, end-use load shapes were used to allocate the annual energy savings to hours. Typical day load shapes for each month were developed for each major customer segment, end-use and IOU using the load shapes developed as part of the commercial end-use survey (CEUS)[14] and the load shape update initiative (LSUI).[15]

Figures 4-5 and 4-6 provide an illustration of the change in load shape that results from the load shapes of the energy efficiency measures included in Case 3A. Figure 4-5 shows a typical week in April. The energy efficiency shape is at the bottom of the figure. The unadjusted load shape is at the top, and the intermediate curve is the resulting shape for total California load once the energy efficiency measures have been subtracted. Since the energy measures have an on-peak emphasis, the resultant load shape is slightly less peaky than the original load shape. Figure 4-6 for a typical July week shows even more clearly that the energy efficiency measures reduce peak demand.

Since POU data on energy efficiency potential were not readily available, relative magnitude considered to be feasible, costs per unit, and load shapes were applied to the POU transareas based largely on how those POU service territories would be expected, climatically, to emulate one of the three IOU service territories for which the ITRON study was performed. The POUs were generally assumed to achieve the same EE savings as a percent of retail sales as the IOU to which they were assigned. In the case of SMUD, LADWP, and IID, discount factors were applied to conservatively reflect that the potentials on a per customer basis are not as large as for the IOUs. LADWP and SMUD were assumed to achieve 75 percent of SCE's and PG&E's percentage savings, respectively. IID was assumed to achieve 50 percent of SCE's percentage savings. The IOU costs per kW saved and load shapes were used for the POUs.

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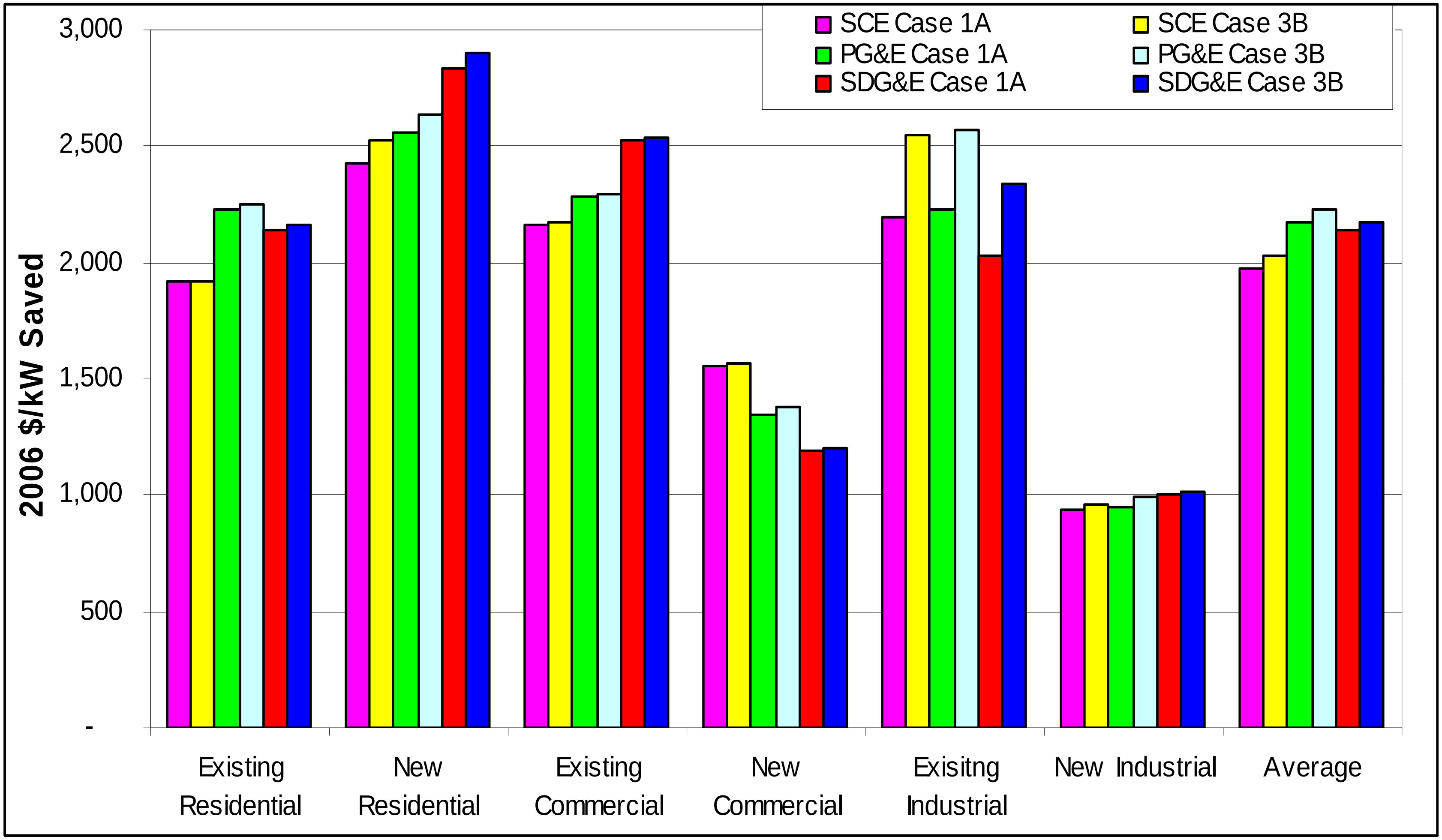
[14] ITRON, March 2006, "Commercial End-Use Survey," prepared for the California Energy Commission, CEC-400-2006-005.

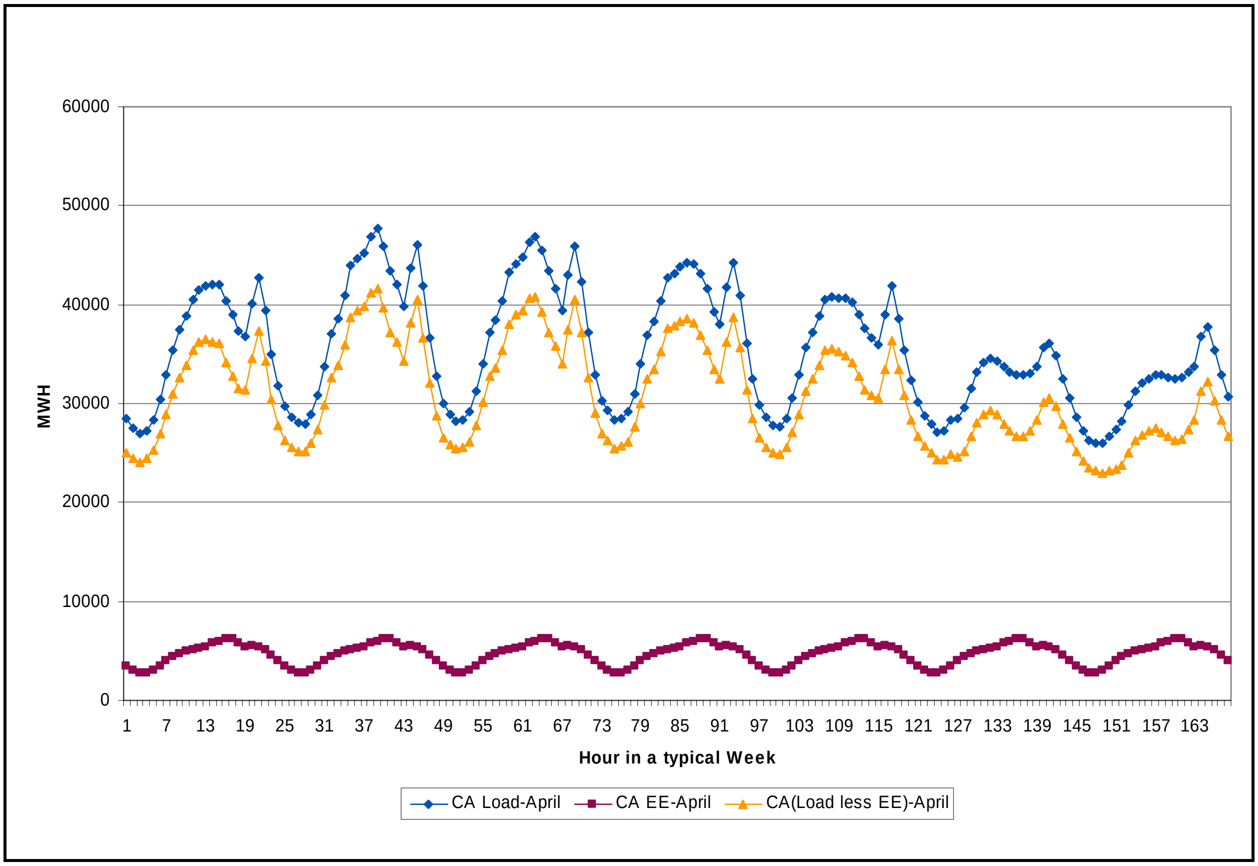
[15] KEMA, JJ Hirsch Associates, November 17, 2006, "Load Shape Update Initiative, Final Report," prepared for the California Public Utilities Commission.

Figure 4-4: Expected Cost of Energy Efficiency Savings



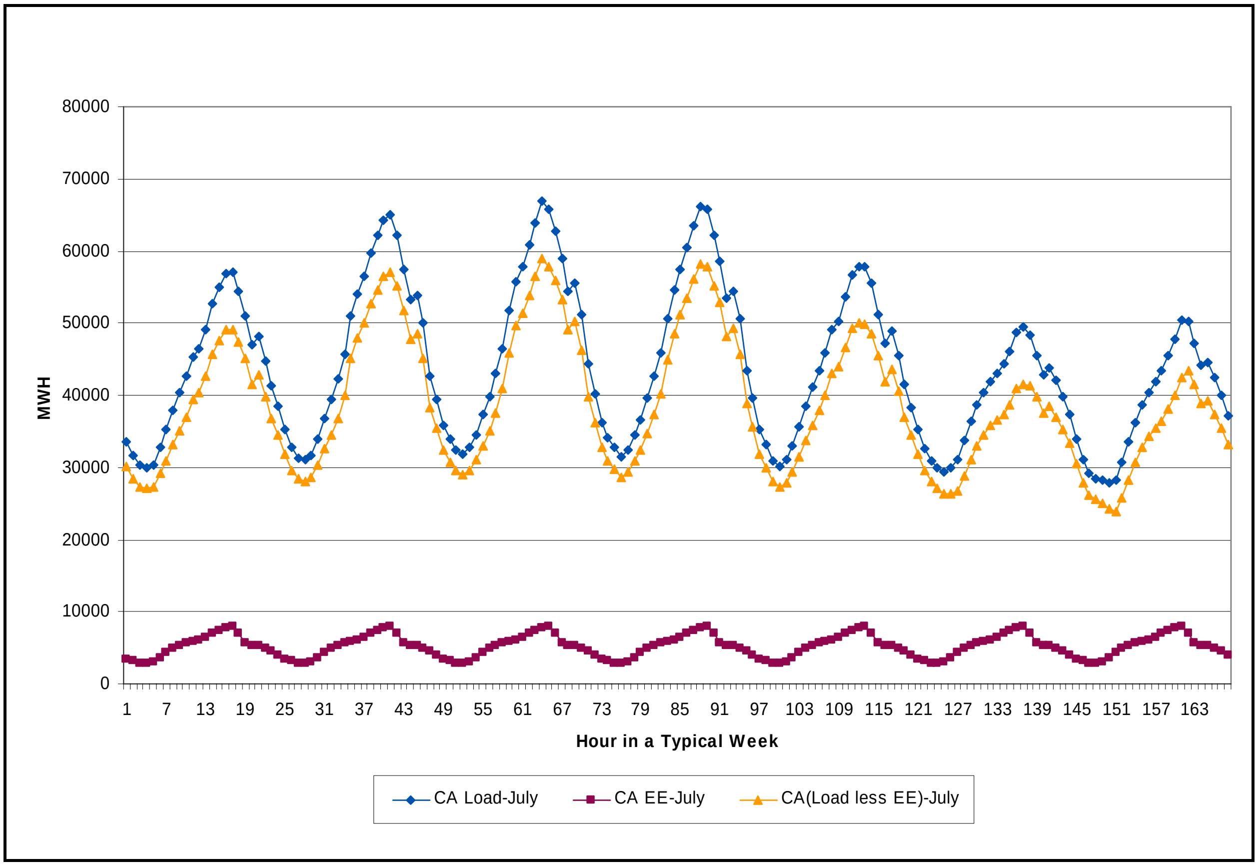
Source: Navigant Consulting

Figure 4-5: Energy Efficiency Impact on Loads for Typical April Week



Source: Navigant Consulting

Figure 4-6: Energy Efficiency Impact on Loads for Typical April Week



Source Navigant Consulting

4.2.2 Energy Efficiency in Rest-of-WECC Areas

No comparable energy efficiency potential study exists for the non-California portions of WECC. The CDEAC energy efficiency recommendations assert 20 percent reduction in load from their reference forecast. The analysis included a "current activities" scenario that reflects a 9 percent savings relative to the reference forecast. There are uncertainties about whether this level of EE is actually included within utility load forecasts, as a recent LBNL report suggests something somewhat lower.[16] Despite the LBNL report, we assumed that the current activities scenario was already embedded in the utility forecasts that this study used. This difference in conclusions indicates that there is considerable uncertainty about the current level of EE activity and the available resource opportunity.

The current activities scenario included impacts from building standards, appliance standards and utility programs that are already in place. The difference between the "best practices" and "current activities" scenarios is about 10.9 percent of the reference forecast loads. Thus an additional 10.9 percent savings by 2020 from implementing "best practices" was used as the estimate of the achievable energy efficiency resource base for the rest-of-WECC. The annual average growth rate after this energy efficiency in the rest-of-WECC is still 1.17 percent per year, which is considerably higher than the no-growth consequences of the "best practices" scenario in the CDEAC analysis.

The CDEAC analysis did not include costs or load shapes; therefore costs and load shapes derived from the analysis of California IOUs for Case 3A were used based on the IOU that is climatically the most similar to each Rest-of-WECC transarea.

4.3 Demand Response

There is no known "potential" study to draw upon for demand response; therefore, this study developed the possible penetrations of DR programs and their costs from a review of available demand program studies. Reliance upon existing programs may not capture the actual potential for DR that exists in either California or Rest-of-WECC.

For California, the IOUs and larger POUs submitted demand response program impact and cost data to the CEC as part of the 2007 IEPR proceeding. These data, and similar data provided by the IOUs to the CPUC in December 2006 in the Long-Term Procurement Proceeding (LTPP), were used to identify an additional increment of demand response for use in Case 3A beyond that included within Case 1B. DR capacity was not increased for SCE for Case 3A, because they were forecasting DR capacity for equal to 7.4 percent of their peak load. For Case 3A, it was assumed that PG&E would exceed the 5 percent goal and attain 6 percent DR capacity. For Case 3A, we assumed that SMUD and SDG&E would increase their DR capacity to 5 percent of their peak load, while LADWP would attain DR capacity equal to 3 percent of their peak load, still 10

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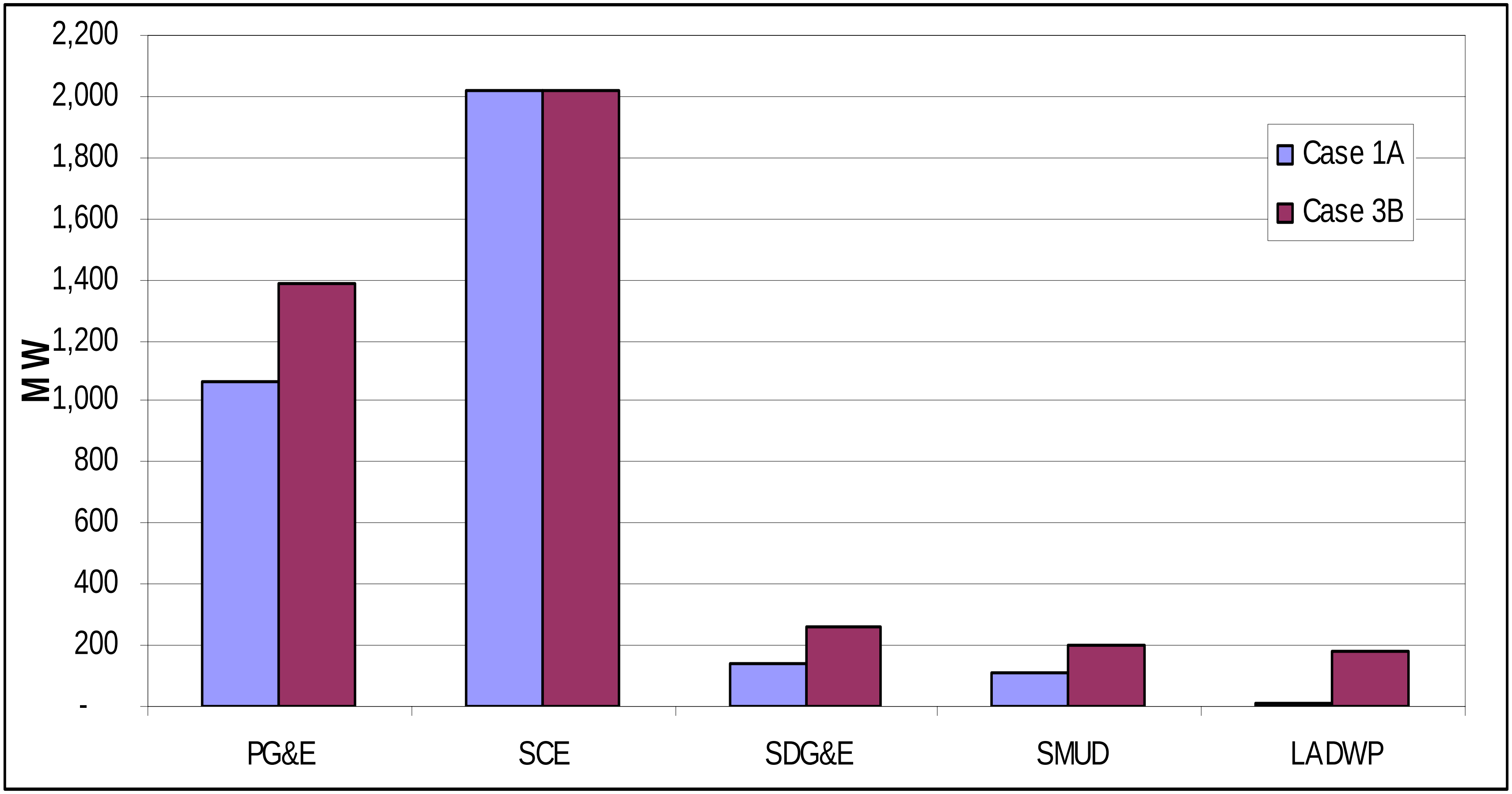
[16] Lawrence Berkeley National Laboratory, August 2006, "Energy Efficiency in Western Utility Resource Plans: Impacts on Regional Resource Assessment and Support for WGA Policies," LBNL-58271.

times as much capacity as reflected in their own DR forecasts submitted into the 2007 IEPR proceeding. The DR capacities are summarized in Figure 4-7. The cost of the DR capacity was assumed to be $100/kW, except for SMUD whose cost was $360/kW.

For the Rest-of-WECC transareas, despite initial plans to increase the level of DR in Case 3B, the final study did not include hypothetical additional demand response for transareas outside of California. Two reasons account for this change. First, the need for such resources did not exist. Virtually all Rest-of-WECC transareas already exceeded planning reserve margin (PRM) targets in Case 1B. In addition, the method used to develop the Case 3B resource plans increased reserve margins beyond PRM targets simply by energy efficiency additions and the inability to backout sufficient generic fossil additions to match the capacity added. Under these circumstances, no real need exists for a resource with DR's limited capabilities. Second, there was very limited availability of supporting information for programs outside of California. Clearly, this is an area where more information could be useful to future studies.

Figure 4-7: Dispatchable Demand Response Capacity by Utility and Case



Source: Navigant Consulting

4.4 Supply-Side Renewable Generating Technologies

Wind, geothermal, biomass and concentrating solar generating technologies were examined for use in all of the cases. In Cases 4A, 4B, 5A, and 5B, the characteristics of these technologies were crucial to the results. Section 4.1 provided the basic technology and operating cost information for these technologies. This section focuses on the following features:

- Potential by transarea for each technology;
- Expected at-peak performance and typical daily production profile for each month.

For wind and solar generating technologies that experience wide fluctuations in performance, data were gathered and processed to allow variations in hourly production profiles and performance degradation under peak demand conditions. This evaluation was an important factor in determining the level of otherwise expected conventional generation that could be removed from the resource additions by region. No change in technology cost of performance was assumed for new installations through the study period.

4.4.1 California Renewable Development Patterns

It is impossible to accurately predict how the many kinds of supply-side renewable technologies will develop through time in response to legislative mandates, utility regulatory requirements, various government subsidies, and market forces. Further, the geographic location of renewable development is more constrained that that of conventional generating technologies, since some renewable technologies are tied to specific locations. Wind development occurs where wind potential is greatest. Geothermal development happens where geothermal resources are readily tapped.

Two different approaches were used to determine the mix and location of renewable development in California. The first devised a development pattern and technology mix that extends the current patterns of development and assumes that renewables would develop to satisfy existing California RPS. The second assumed that a different pattern would emerge if a high penetration of renewables were to develop. The general approach for both existing and high development patterns is explained separately in the remainder of this subsection.

4.4.1.1 Current Renewables Development Pattern

Energy Commission staff have projected the resource development pattern for California renewables, along with the Rest-of-WECC, for several resource planning studies that require built-out resource plans. The collaborative transmission planning effort in 2005 is an example of such an effort.[17] This effort was updated for the 2007 IEPR proceeding by reassessing the evolving RPS requirements of various states to guide renewable development.

4.4.1.2 High Renewable Development Pattern

The Energy Commission PIER program is conducting a multi-phase research project to better understand wind integration issues and solutions. Phase 2 of this effort is known as the Intermittacy Analysis Project (IAP). IAP completed its analyses and conducted a public workshop in February 2007. The IAP project analyzed different penetrations of several different renewable technologies for years 2010 and 2020. Some scenarios presumed that renewable development was constrained by the existing transmission system and other determined how the transmission system should be expanded to accommodate higher penetrations of renewable development. The IAP resource additions by nameplate capacity and transmission bus locations for a 33 percent renewables by 2020 assessment were used in this study. Other detailed characteristics of the resources were taken from other studies.

Thus, this study did not develop or work from a true renewables potential study. Instead, this study borrowed from the IAP results to define a high renewables scenario and supplemented IAP assumptions were necessary to fully characterize these technologies for the metrics examined in this study. Information on the IAP-based resources was utilized to identify the amounts of certain renewables that were assumed to be developed within each transarea within California. Hourly production profiles, annual capacity factors, and costs were developed specifically for this study.

For the purposes of the Aging Power Plant assessment, information from the IAP was used to assign both PV and biomass resources to specific busses within Southern California in the powerflow basecases developed to assess retirement impacts for Cases 1B, 3A, and 4A. These resources were assumed to be interconnected with the lower voltage system (69-kV and below) and, as such, did not require modifications to the transmission system. In the Aging Power Plant assessments, other renewables (wind, solar, and geothermal) were assigned to the various assumed interconnection points on the transmission grid based on information in the generation interconnection queues of the California ISO, SCE, and IID.

[17] During 2003 to 2005, the vision of three regional transmission organizations led to the development of the Seams Steering Group – Western Interconnection (SSG-WI). SSG-WI created several technical groups, one of which fostered the development of collaborative transmission planning. SSG-WI transmission planning study activities have now been replaced by a formal body created by WECC – Transmission Expansion Policy and Planning Committee (TEPPC). Energy Commission staff contributed to the voluntary efforts of SSG-WI and now participate in TEPPC.

4.4.2 Rest-of-WECC Renewable Development Patterns

Despite substantial interest in supply-side renewable development and several major transmission line proposals that would make use of renewables as part of the supply additions justifying these lines, there is no good source of renewable potential and its costs in the form of a locational "supply curve." Thus, as with other scenarios, this study started from previous studies of renewables and tried to adapt these for the purposes of this study within the time and resources of the project.

Energy Commission staff have conducted several studies to build out the RPS requirements of Rest-of-WECC for resource planning and transmission studies. As noted above, these can be thought of as extensions of existing patterns guided by RPS requirements of the various states. These Energy Commission staff studies were used in Cases 1B and other cases reflecting current requirements. However, these assessments only were prepared out to 2017, so extensions for 2017 – 2020 were prepared as part of this study.

High levels of renewable development are more speculative. This study relied upon estimates made by the Clean and Diversified Energy Advisory Committee (CDEAC) of the Western Governors Association (WGA). CDEAC consisted of 31 members that represented a wide range of interests from WGA member states and provinces. The CDEAC was charged with the task of identifying incentive-based, non-mandatory recommendations that would facilitate 30,000 megawatts of new clean and diverse energy by 2015. The CDEAC process, which culminated in reports to the Western Governor Association in May 2006, conducted extensive stakeholder reviews for each of the major renewable technologies. The locations of renewable resource potential in the Rest-of-WECC transareas were used to determine the capacity additions for Case 4B and 5B were guided by the amounts of renewable generation and location of that generation as reported by the Transmission Report of CDEAC.

Table 4-2 reports renewable development "potential" for four technologies by state of location.[18] The amounts of renewable technologies included in Cases 1 and 1B are smaller than these potentials. Thus, Case 4B could include a further increment of renewable capacity as long as the cumulative amounts did not exceed these limits. As with other elements of this study, this approach imposes all of the limitations inherent in the original CDEAC effort.

[18] Data on Figure A-2 of the May 30, 2006, CDEAC Renewable Report identified renewable development thought to be economically feasible by 2015.

Table 4-2: Renewable Technology Economically Feasible for Development by 2015 in Rest-of-WECC (MW)

	Total Incremental Installed Capacity (MW)				
Transarea	Wind	Biomass	Geothermal	Solar (CSP)	Total
Arizona	1800	0	0	950	2750
Colorado	915	0	0	92	1007
Idaho	0	855	796	0	1651
Montana	1700	0	0	0	1700
Nevada	1139	0	1047	450	2636
New Mexico	6000	0	0	300	6300
Northwest	3260	0	0	0	3260
Utah	570	0	230	0	800
Wyoming	5355	0	0	0	5355
Total	20739	855	2073	1792	25459

Source: CDEAC Transmission Report, High Renewable Scenario Generation

4.4.3 Renewable Technology Electricity Production Profiles

In the PROSYM deterministic analysis, typical day hourly generation profiles by month were used in the modeling of renewable energy resources that typically have variable availability. These resource types include wind, concentrated solar power, and photo-voltaic solar. For modeling wind generation in California, Energy Commission staff provided historical hourly wind profiles for 2003 through 2005 for locations across California of which only the 2003 hourly shape was used. For modeling wind generation outside of California, hourly wind shapes were obtained from the National Renewable Energy Laboratory (NREL), which were derived from historical hourly wind data. For modeling concentrated solar power (CSP), hourly data were also obtained from NREL; however, only one twenty-four hour daily shape was provided for each month of the year. The twenty-four hour CSP shapes were duplicated for each day of the week to derive a typical week for each month of the year. For modeling photo-voltaic, Navigant Consulting provided hourly shapes for each of the transareas where rooftop solar PV was being modeled.

In the stochastic analysis, where of the renewable resource type only wind and rooftop photo-voltaic was treated stochastically, daily-hourly profiles were drawn for each day of each month for 100 iterations. For example, for Iteration 1 - January 1, any 24 hour daily shape of January would be used in the stochastic simulation. Following the example, Iteration 2 - January 1 could use the hourly generation profile from January 30. On Iteration 3 - January 1, the actual historic January 15 hourly daily profile might be used. This process continued until all 100 iterations were created for each day of the simulation for each transarea. Similarly, the 100 iterations for January 2 would also draw from the 30 daily profiles available for a January day. Global Energy used its Historical Wind Generation Tool to produce the iteration data input to the model.

4.5 Rooftop Solar Photo-Voltaic

The California Solar Initiative (CSI) is being implementation through the collective efforts of the Energy Commission and the CPUC. The goals for this initiative require that this study address rooftop solar PV in a serious manner. This subsection describes technology characteristics and alternative penetration projections, which are the key inputs for the various cases prepared for this study.

4.5.1 PV Technology Characteristics

PV performance is affected by weather of the locations of PV rooftop installations. National Renewable Energy Laboratory (NREL) simulated hourly production profile data called "PV Watts" was used in this study. Hourly data for an entire year derived by the NREL as typical average PV production by geographical location was used to estimate the PV contribution to meeting load throughout the West, including California. The source of this data and the methods used to apply it are described in more detail in Appendix G-2. Global also maintained the 8760 hour PV production data profiles and used them in its stochastic assessments that are described in Section 6.6.3 of this report.

The PV Watts data base has 12 sites available for all of California. For each location, the insolation, elevation, assumed tilt of the solar array, rating per square foot, and DC to AC conversion efficiency is applied to develop hourly production per kW of installed PV capacity. The information for those 12 locations of "PV Watts" data sets were then extrapolated to the transmission areas within California to determine the level of PV contribution by year. More detail regarding data sources and analysis is provided in Appendix G-2.

PV cost reductions through time are essential to achieving the development goals established by policy-makers. Near-term installed costs were assumed to be $10,000 per kW, while longer-term costs were assumed to be $5,000 per kW. In a departure from the general assumption about technology costs staying fixed through time as explained in Section 4.1, this is the single technology for which costs were allowed to change through time. These two cost regimes for rooftop solar PV are also different than the assumptions prepared for the COG study, which were included in Figure 4-1.

4.5.2 PV Penetration Assumptions

The California Solar Initiative motivated the Energy Commission to examine various penetration possibilities. A PIER-funded research study by Navigant Consulting provided several scenarios for the build out of rooftop PV in California on a county-by-county basis for residential and commercial/industrial customers. [19] This evaluation considered both "utility subsidies" and more aggressive business and marketing plans to develop a range of potential PV installation over the study period.

A Navigant Consulting study for the State of Arizona provided multiple cases for use in various cases for that transarea. A less sophisticated assessment was conducted for Nevada. Rooftop PV was not assumed for any other state.

Funding of PV supplies is based on Total Resource Cost and assumes the funding comes from borrowed money and an 11.1 renewables per year levelized fixed charges rate as a customer-installed investment reflecting certain assumptions regarding future tax treatment.

Installed cost estimates used in this analysis were provided under two scenarios: a "business as usual" case of continued, but not increased State PV incentives, with no introduction of new business models to increase PV penetration and an "aggressive" case, described below. Estimates were prepared for PV installations in 2006, 2010 and 2016. Factors such as housing growth rates, PV module efficiency, available roof space allocated to PV for available residential and commercial roofs, the average pitch of roofs, shading factors, and orientation of structures. These factors were then combined with climate zone by county and system power density was calculated using PV module efficiency to result in the technical potential for PV installation by county.

Market penetration in MW was evaluated considering pay-back period and market penetration percentage considering retail utility rates by county, cost of systems, pay-back and capacity factor. The penetration rates were estimated assuming continuation of State incentives for the business as usual case. The Solar Generation Incentive Program (SGIP) was assumed for commercial systems and Energy Rebate Program (ERP) was assumed to apply to residential systems.

For the more aggressive PV penetration scenario, in addition to continuation of State PV incentives, new business models were assumed to be adopted, resulting in lower cost installations and therefore higher market penetrations. These new business models include programs such as the packaging and marketing of PV systems as a home appliance. Other business models include bundling of PV installation services into a single entity provider that provides the equipment, installation, rebate application maintenance and financing. A third business model provides for standard consumer finance models to be applied. Additional description of the methods and assumptions used are provided in Appendix G-1.

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[19] Navigant Consulting, California PV Market Assessment, Prepared for PIER Renewables.

For the period of this study, Arizona and Nevada are considered the highest prospect for additional PV, after California, in the rest of the WECC on a total installed capacity basis. Therefore, these two states were the focus of estimates for the Rest-of-WECC PV contributions to load. Unlike for California, there is no county-by-county assessment of customer-installed PV potential for either Arizona or Nevada. No statewide PV penetration potential of the level of detail of that performed for California, as described above, is available. However, Navigant Consulting evaluated PV penetration potential on an aggregated basis for the Arizona Department of Commerce in the *Arizona Solar Electric Roadmap Study*, October 2006. This study developed estimates for two levels of PV penetration based on continuing the current utility-only incentives for customer-installed PV, as a basecase, and additional PV penetration from a broad state program to encourage accelerated PV development in Arizona.

The continuation of utility-based incentives is assumed in both cases, and the accelerated case assumes establishing specific solar policies and programs, marketing and outreach efforts at the state level, creation of special zones for PV investment and installation and related actions the state could undertake to increase PV penetration and contribute to the Arizona economy. This programmatic approach was estimated to increase PV penetration by a factor of six, from an estimated less than 40 MW by 2020 to about 250 MW by 2020 in the accelerated case. PV concentrations in Arizona were assumed in major load centers and distributed to contribute to load reduction at key locations on the Arizona grid for the respective cases.

No comparable PV penetration analysis was available for Nevada, although Nevada, and particularly southern Nevada, has similar solar resources as Arizona and has concentrated and growing numbers of utility customer candidates for PV installation. Opportunities available to Nevada for accelerating PV installations are similar to those of Arizona. To provide estimates of PV penetration in Nevada in the absence of detailed study information, for the Cases involving assumed high levels of renewables, the contribution of rooftop, customer-installed PV was estimated to equal Arizona's incremental capacity addition between the Arizona basecase and the accelerated penetration case. This results in the high PV penetration case for Nevada with 255 MW in 2015 and 450 MW in 2020. This contribution of customer-installed PV to meet demand in Arizona and Nevada is the basis for estimating PV penetration in the US portion of the WECC outside of California, and electric loads in those states were adjusted accordingly in this study.

More detailed description of PV penetration analysis and assumptions is provided in Appendix G-1.

4.6 Advanced Gas-Fired Technologies

Advanced gas-fired technologies were used to fill out each case to satisfy resource adequacy criteria when the levels of preferred resource types were insufficient. Combined cycle gas turbines (CCGT) were used when modeling indicated that a new CCGT would be able to recover its full cost. Simple cycle combustion turbines were used when CCGTs were not economic, but something was needed to maintain an appropriate planning reserve margin. The characteristics of these technologies were an amalgam of features drawn from a Frontier Transmission Line study and a PIER research project supporting the COG project undertaken by the Energy Commission staff. No change in technology cost or performance levels was assumed over the study period.

In this study, new combined cycle generation has a levelized fixed revenue requirement of $138/kw/yr. New peakers are assumed to have a levelized fixed revenue requirement of $156/kw/yr. This cost for a new simple cycle gas turbine is reflective of smaller units that are more responsive and have better heat rates. This type of peaker is more expensive to build than large “frame” technology peakers.

For this study, we reflected the revenue requirement for the capital and fixed O&M of new gas fired generation on a levelized $/KW/yr basis. Such an approach indirectly addresses end effects by only including the annual revenue requirement in the years for which the study is done. The new gas fired technologies added in the study period will last beyond the end of the study period. By only including the annual revenue requirement in the years of the study period, the lifetime revenue requirement of the plant is not included, thereby permitting a loose match of costs and benefits for the period being studied.

4.7 Transmission System Elements

Some cases required explicit transmission system upgrades to support specific levels and likely locations for resource additions. This study prepared a preliminary assessment of the transmission system upgrades and their costs to match the generation build-out assumptions of each case.

4.7.1 Incremental Inter-Zonal Transmission Additions

If the zonal modeling showed that paths between zones would experience a high level of congestion, those paths were assumed to be upgraded (at a cost) in order to reduce the congestion. A rough estimate of transmission upgrade and/or transmission development using $/line mile values and estimated line lengths were used to identify a first order approximation to incremental transmission costs compared to a base year. Except in some limited instances, such as in variants of cases involving retirement of aged generation and some assessment of bringing wind energy to load, there was not an assessment of intra-zonal transmission upgrades that could be required – so the transmission line mile additions accounted for in this study and incremental transmission costs are mainly the inter-zonal subset of total transmission additions.

For this study, future transmission needs were determined from two standpoints. First, if Case 1 assumed generic additions were removed from an area and no supply with equal contribution to satisfying resource adequacy guidelines was added in that region, then a new transmission capacity would be needed in that area to support imports from any transareas that added more generation. Second, if the hourly dispatch model run for that Case showed significant increase in transmission congestion between transareas, then new transmission capacity would be needed to reduce the congestion.

4.7.2 Incremental Intra-Zonal Transmission Additions

Navigant Consulting used the PSLF model to perform transmission system analysis that provided insight in to specific transmission system improvements that would likely be required within the SCE and IID Transmission Areas to support the development of resources in these Areas and, in the case of the IID Area, the export of renewable resources out of the Area.

The identification of the intra-zonal transmission improvements for the SCE Area was done as part of the Aged Power Plant retirement evaluation. In these evaluations, detailed powerflow studies were performed for both normal and contingency conditions on the transmission system for Cases 1B, 3A, and 4A for three different load levels (2012, 2016, and 2020 1-in-10 peak loads) to identify transmission constraints that would exist within the SCE Area for each Case and to identify potential methods of mitigating these constraints.

4.7.3 Transmission Cost Characteristics

Unit cost information for 500-kV, 345-kV, and 230-kV transmission lines and related facilities were used to develop the estimated costs for the various inter-regional and intra-regional transmission upgrades identified during this analysis. These unit costs are summarized in Table 4-3.

Table 4-3: Unit Costs Used in Developing Preliminary Transmission Cost Estimates (Millions of $2007)

Transmission Line Element	500-kV Facilities [20]	345-kV Facilities [21]	230-kV Facilities
Transmission Lines ($/Mile)			
- In California	2.15	n/a	1.1
- In Rest-of-WECC	1.75	1.6	0.65
Line Terminations (Each)($M) [22]	26	12	10
Series Capacitor Banks (Each)($M) [23]	10	6	n/a
SVCs (Each)($M) [24]	30	17	n/a

As an example for using Table 4-3, the estimated cost for a 150 mile long, 500-kV line within California would be approximately $455 million, consisting of:

- $322,500,000 for the transmission line itself (150 times 2.15),
- $52,000,000 for the line terminal equipment (2 times 26),
- $20,000,000 for series capacitors (2 times 10), and
- $60,000,000 for SVCs (2 times 30).

4.7.4 Transmission Cost Estimates

Table 4-4 summarizes information relative to the in-service year, amount of capacity added, assumed operating voltage, assumed line length, and estimated costs for the various inter-regional transmission path upgrades discussed in Chapter 2 for the various cases. The estimated lengths for the various transmission paths in Table 4-4 were derived from various sources such as the CDEAC and RMATS reports and from transmission maps and other data available to Navigant Consulting.

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[20] Based on information in "Frontier Line Analysis of Transmission Links and Costs to be Used by the Economic Analysis Subcommittee" Draft Report – Revision 3 (October 30, 2006).

[21] Based on information in CDEAC Transmission Task Force Report (May 2006).

[22] Includes circuit breakers and line reactors (for 500-kV lines only).

[23] Assumed that two series capacitor banks would be added in each line segment.

[24] 300 MVAR SVCs assumed for 500-kV lines; 150 MVAR assumed for 345-kV lines.

Table 4-4: Detailed Information on Inter-Regional Transmission Path Upgrades

Case	From Area	To Area	Year	MW Increase	Assumed Voltage	Assumed Line Length	Estimated Cost ($ Millions)
1B	Alberta S	Montana	2008	300	230	190	176
	Arizona	So. Nevada	2009	1,430	500	250	570
	BC	Northwest	2009	500	500	245	693
	IID	SCE	2009	1,000	500	85	315
	Wyoming	Idaho	2010	700	500	545	1,350
	Imperial	SDG&E	2010	1,150	500/230	178	1,415
	Montana	Northwest	2011	500	500	n/a[25]	15
	Wyoming	Utah	2011	500	345	410	745
	Wyoming	Idaho	2012	800	500	545	1,350
	Montana	Northwest	2013	500	500	670	1,833
	Wyoming	Utah	2013	500	345	410	754
	Alberta S	Montana	2014	500	500	450	920
	Alberta S	BC	2016	500	500	150	395
4A	IID	SCE	2015	500	230	280	262
	SCE	LADWP	2015	500	500	n/a[26]	50
	IID	IV-NG	2015	700	230	80	92
4B	Wyoming	Utah	2013	1,200	345	820	1,507
	Northwest	Idaho	2015	500	500	365	903
	Wyoming	Colorado (E)	2015	500	345	256	627
	Wyoming	Colorado (W)	2017	500	345	300	464
	New Mexico	Arizona	2018	1,600	500	1,370	3,323
	Idaho	No. Nevada	2018	500	500	250	570
	Montana	Wyoming	2018	500	345	200	334
5B	New	Arizona	2013	900	500	[27]	

[25] Assumed to be addition of series capacitors in lines.
[26] Upgrade terminal equipment on existing line.
[27] Capacity assumed to be available in New Mexico-Arizona upgrades in Case 4B.

	Mexico						
	Wyoming	Utah	2015	500	345	410	754

CHAPTER 5: METHODOLOGY FOR EVALUATING CASES

This chapter provides an overview of the methodology used to prepare the analyses of the base thematic scenarios and the various alternative cases. While there is inherent uncertainty about the fundamental features of the scenarios, they were evaluated using production costing models and transmission load flow models characterized by a great deal of precision. Using such tools has drawbacks. Less sophisticated analytic tools might have allowed for a greater number of scenarios with a series of alternative penetrations of the basic strategies of energy efficiency and renewables. Modeling approaches that better incorporate uncertainty both of the basic scenario features and many other parameters used in the evaluations might also have been used. The high precision tools that were used also have advantages. They force numerous assumptions to be thought through to the level of input detail required by the models. They reveal insights in results that may not be obtained with other techniques. They add credibility to the results that less sophisticated tools might not.

This chapter briefly outlines the various elements of the modeling tools that were used in the project. The description assumes a familiarity with these tools and techniques.

5.1 Zonal Production Cost Modeling with Inter-Zonal Transmission Limitations

Global Energy supported this project through use of its PROSYM production cost modeling tool operated in a zonal basis. Zones, called transareas in this report, are defined as groupings of power plants and the loads they serve. Transmission constraints limit power flows between transareas, but the model does not assess transmission limitations within transareas.

Starting with Global Energy's Fall 2007 WECC Power Market Reference Case, Energy Commission staff recommended changes in certain aspects of the modeling set-up and input assumptions. The main changes recommended by CEC staff were to make minor adjustments in model topology to better reflect zones within California, to change the natural gas price forecast to more closely conform to long-term preliminary 2007 outlooks by EIA for oil price forecasts, and to conform California load forecasts to that prepared by the Energy Commission staff reflecting the long-term extension of the 2007 load forecasts adopted in June 2006.

Details of Case 1 (Current Conditions) are described in Appendix B-1.

5.1.1 Topology for Modeling

A topology defining the Western Interconnection as 29 transareas was used for this project. Ten of these are located in California, and 19 are used to characterize the Rest-of-WECC. A topology map is shown as Figure 5-1 along with the transfer capacities between zones that allow power to flow from one to another. A few of these are defined as generation hubs with no end-user loads. Palo Verde is one such transarea. A table enumerating each transarea is included as Table 5-1.

5.1.2 Fuel Price Projections

Although Global Energy prepare its own fuel price projections, the Energy Commission staff wanted to use a natural gas price forecast more closely aligned with the most recent EIA forecast of natural gas prices. Further, rather than simply using the EIA projections themselves, staff wanted a gas price modeling capability to conduct sensitivity cases around variations in fuel prices, and to explore the implications of lower natural gas consumption in power generation on natural gas market clearing prices.

As part of its natural gas forecasting practices, Global Energy licenses GPCM®, a natural gas model of the North American natural gas system licensed to Global Energy Decisions by its owner the Robert Brooks and Associates Company. Appendix H-1 provides an overview of GPCM® and how it is interfaced to provide market price values for specific groupings of electric power plants.

In order to satisfy these requirements, Global Energy reran its natural gas price forecast model using a higher oil price forecast, which came from the most recent federal Energy Information Administration (EIA) oil price forecast. Resulting natural gas prices were quite similar to the EIA most recent forecast of natural gas prices. Having "calibrated" Global's fuel price forecasting model in this manner, its capability was available to use in other aspects of this project. Appendix H-2 provides a summary of the means by which Global "calibrated" its Fall 2006 fuel price projections.

5.1.3 Electricity Load Forecasts

Even though the Global Energy Fall 2006 Reference Case already included load forecasts for all transareas, including those in California, the Energy Commission staff naturally wished to use the latest Energy Commission forecast of California loads. The most recently available Energy Commission load forecasts were prepared in June 2006. Peak demand values for 2007 were adopted by the Energy Commission in that same month. An extension of that vintage of load forecast was available for the long term, so it was used.

Figure 5-1: Topology of the Western Interconnection Used in the Analysis

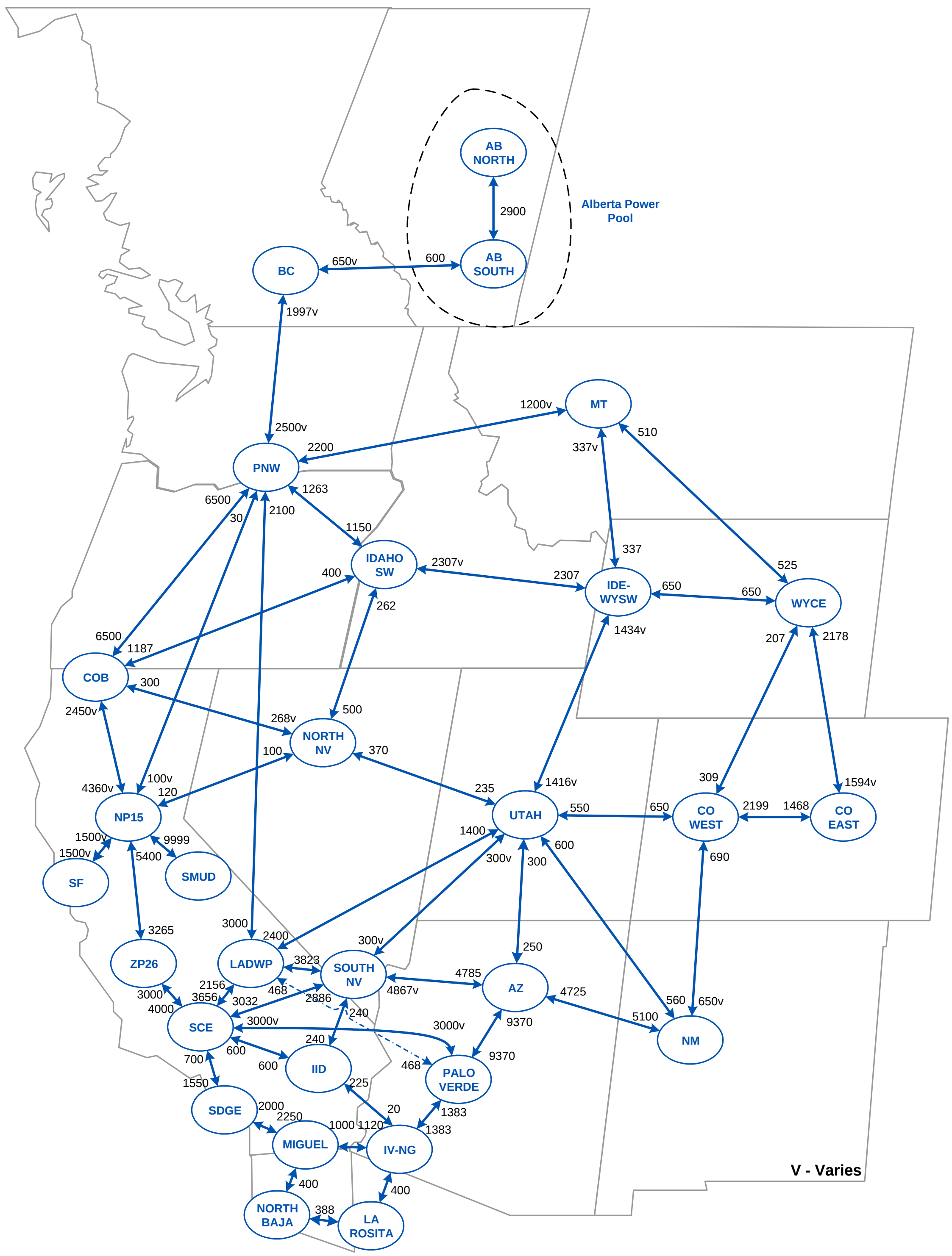


Table 5-1: Transareas Used in Analysis

No.	Abbreviation	Name	Geographic Location
1	AB_S	Alberta - South	AB (Canada)
2	ABCN	Alberta - Central-North	AB (Canada)
3	Arizona	Arizona	AZ
4	BC	British Columbia	BC (Canada)
5	CNP15 (CNORTH)	California ISO Northern California	CA
6	CO_East	Colorado - East	CO
7	CO_West	Colorado - West	CO
8	COB	California - Oregon Border Transmission Hub	CA, OR
9	CSCE	CaliforniaISO - Southern California Edison	CA
10	CSDGE	CAISO - San Diego Gas & Electric	CA
11	CZP26	CAISO - Zone Path 26 PG&E South	CA
12	La Rosita	La Rosita	Baja (Mexico)
13	IdE_WYSW (Wyoming W)	Idaho Power East -Wyoming South West	ID, WY
14	Id_ SW	Idaho Power West	ID
15	IID	Imperial Irrigation District	CA
16	IV-NG	Imperial Valley	CA
17	LADWP	Los Angeles Department of Water & Power	CA
18	Miguel	Miguel - East of San Diego	CA
19	Montana	Montana - Northwest Energy	MT
20	N Nevada	Northern Nevada - Sierra Pacific Power	NV
21	NBAJA	Northern Baja California - CFE	Baja (Mexico)
22	New Mexico	New Mexico	NM
23	Northwest (PNW)	Puget Sound	OR, WA
24	PV	Palo Verde	AZ
25	S Nevada	Southern Nevada	NV
26	SF	San Francisco	CA
27	SMUD	Sacramento Municipal Utility District	CA
28	Utah	Utah	UT
29	WYCE	Wyoming Central East	WY

	(Wyoming E)		

5.2 Building Out Resource Plans

Each case developed a resource plan in which the capacity of resources was sufficient to cover the forecast of peak demand in that transarea. Imports were allowed to contribute to this resource mix. Since this project was assessing the implications of "what if" scenarios, some of the steps normally encountered in a resource planning exercise were either omitted or performed in an unusual manner. For example, rather than focusing the analytic effort on what resources to add to construct a high renewables resource plan, the essential challenge was to determine which of generic resources added in Case 1 should be removed in light of the characteristics of the renewable resource additions that were assumed in the definition of the scenario itself.

5.2.1 Resource Additions to Satisfy Resource Adequacy

Each case was required to have a resource plan that satisfied a simplified resource adequacy requirement that included several distinct elements very loosely adapted from California's resource adequacy requirements to have 15-17 percent planning reserve margin (PRM) relative to a 1:2 peak demand.[28] These were:

- A minimum 15 percent planning reserve margin applied to the historic month of control area peak demand for each transarea,
- No elimination of existing resources or named additions to "force" the transarea to down to a minimum 17 percent PRM,
- Discounting wind and rooftop solar PV nameplate capacity to follow the net qualifying capacity rules established by the CPUC to establish estimates for qualifying capacity, and
- Permitting imports into the control area based on information available about transactions.

This simplified resource adequacy requirement was conducted for all loads for all 29 transareas with load. This requirement was established for each control area separately.

An example will illustrate how this was done in Case 1. In the early years of the forecast, many control areas already exceed this PRM level. Later in the forecast period, load growth and resource retirements require additional resources to meet the 15 to 17 percent target in some control areas. The analysis performed for purposes of adding gas turbines for resource adequacy purposes was done by looking at each control area to see if, after adding resources for other purposes, the control area was dropping below a 15 percent planning reserve margin. For winter peaking areas, the winter peak load was used. For summer peaking areas, the summer

[28] California Public Utilities Commission, D.04-01-050, D.04-10-035, and D.05-10-042.

peak load was used. By assuming the peakers were built in the control area, it was not necessary to determine if additional "between control area" transmission would need to be built for resource adequacy purposes. When the diversity of winter versus summer peaking, and within month daily peaking is taken into account, 15 -17 percent at the control area level in the year 2020 translates into 28 percent at the overall WECC level. This discrepancy is heavily affected by having significant diversity in peak seasons, peak months within the summer season, and peak days within the same peak month among the many transareas.

5.2.2 Removing Generic Resource Additions Added in Case 1 as Preferred Resource Mix Cases Were Developed

As greater amounts of preferred resources were added in a specific case, compared with cases developed previously (for example, preparing Case 1B from a starting point of Case 1), generic resource additions were removed. Generally this matched nameplate capacity additions for the resources added with the nameplate capacity of the resources removed. For resources like wind with variable output, dependable capacity was compared with nameplate for the generic resources that were to be removed. Renewable technologies with high expected capacity factors or energy efficiency savings ought to be matched with combined cycle plants, but there were relatively few of these in Case 1 to begin with. At some point, all the generic resource additions in all transareas were removed. Once this point was reached, total resource additions increased and projected reserve margins increased above targeted levels considered sufficient from a traditional resource adequacy perspective.

Table 5-2 provides an illustration of this process for Case 1B starting from Case 1. In this instance Case 1B attempts to incorporate a reasonable interpretation of the statutory requirements, or funding commitments made by PUCs of the various states, on energy efficiency, end-user photovoltaic, and supply-side renewable generation. As noted above, Table 5-2 shows that as a general rule generic thermal resources are displaced by a wide variety of renewable technologies. The slight reductions in wind reflect the assumptions that Global Energy made in developing Case 1, e.g. an assumption wind additions alone rather than a portfolio of renewable technologies would develop through time. Thus, the analysis of renewable additions for Case 1B reduces wind and adds other resources.

Finally, Table 5-2 also illustrates the issue of increasing total capacity as a consequence of substituting renewables and energy efficiency for generic thermal resources.

Table 5-2: WECC-Wide Changes in Capacity in Developing Case 1B from Case 1

Net Increase in Dependable Capacity for Case 1B Compared to Case 1

Resource Type	2009	2010	2012	2014	2016	2018	2020
Hydro	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0
Thermal	-1212	-1692	-2512	-2892	-4712	-5752	-7772
Biomass	192	271	669	894	1057	1057	1057
Geothermal	219	421	909	1215	1368	1410	1454
DependableWind	462	304	415	596	484	77	-324
Dependabe EE	624	1201	2276	3384	4386	5345	6312
Dependable Solar	206	236	621	1357	1424	1478	1534
Dependable PV	103	142	282	421	540	571	607
VDR	1117	1286	1416	1478	1542	1549	1549
Total	1712	2169	4076	6451	6090	5733	4418

5.2.3 Retirement of Aging Power Plants

This section describes a separate assessment of the Energy Commission's *2005 Integrated Energy Policy Report (2005 IEPR)* recommendation that a fleet of aged power plants previously identified in 2003 and 2004 IEPR studies not be relied upon after 2012. The *2005 IEPR* expressed this policy in the following way:

"The Energy Commission recommends the following to ensure long-term contracts are signed that provide adequate electricity supplies for IOUs:

> The CPUC should require that IOUs procure enough capacity from long-term contracts to both meet their net short positions and allow for the orderly retirement or repowering of aging plants by 2012." (pp. 64 – 65.)

The results described in Chapter 6 and the detailed results appendices include retirements upon reaching 55 years following in service date.

Note: A more specific analysis of retirements to conform to the *2005 IEPR* policy customized to each scenario is not complete, but the work is underway and the documentation of its implications for the cases is forthcoming.

5.3 Production Cost Modeling

Global Energy's "EnerPrise Market Analytics" software, a PROSYM based regional production cost model, was used to determine the way in which the resource plan would be operated, and was the source of the majority of numeric results reported in Section 6 of this report.

5.3.1 Overview of PROSYM

PROSYM is a complete electric utility/regional analysis system. It is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour-by-hour (or by half hour or 15 minute increments, if desired) investigation of the operations of electric utilities and interconnected systems. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations.

To perform simulations, the PROSYM system requires: at least one basic set of annual hourly loads; projections of peak loads and energies on a weekly, monthly, seasonal or annual basis for the study of any future period; and data representing the physical and economic operating characteristics (the resource mix) of the electric utility or pool, and any relevant pool or ISO rules. The size of the system being studied, and the duration of the study, are limited only by computer capabilities and not by model restrictions.

PROSYM allows placing local generation requirements and transmission limits and characteristics into sub-regions called transmission areas. Transmission areas are linked to other transmission areas by transmission links.

PROSYM models a variety of generation resources and handles transactions, allowing representation of all standard resource types encountered in routine production cost modeling. Typically each station would be represented by up to 16 characteristics such as minimum and maximum capacity of the unit, heat rate curve, generation ramp rates, etc.

PROSYM's unit commitment and dispatch logic is designed to mimic "real world" power system hourly operation. This involves:

- Minimizing system production cost, and
- Enforcing the constraints specified for the system, stations, associated transmission, and fuels.

PROSYM produces an enormous amount of information in making its hourly simulations. Many standard reports are available to provide summaries from various perspectives. Customized reports can also be prepared.

5.3.2 Special Considerations for Emission Projections

Carbon emissions, criteria pollutant emissions (NOx and SOx), and mercury are computed within the production cost model using emission factors for each power plant (defined as emissions per unit of fuel combusted) times the level of fuel burned in each hour for that plant. These hourly emissions are accumulated into monthly and annual totals as are many other variables and stored in the results database to be later queried when generating results reports.

An obvious style of report is to accumulate all of the properties of associated with individual power plants in the geographic area they are located. In this study, the 29 transareas are the finest level of geographic detail that is reported. Transarea reports have been prepared that accurately depict the fuel combusted, carbon and criteria pollutants, toxic contaminants like mercury released for the specific power plants located in each transarea. The results reported in Appendix D provide annual summaries for each transareas for each scenario. This can be classified as a “source-based” perspective.

In contrast, California has been investigating a “load-based” GHG emission reduction strategy being pursued in California, which requires information about the carbon emissions released in other states that serve California loads along with the California plants supporting those loads. It is insufficient to ignore that a substantial proportion of power serving California loads is generated out of state and imported. Attempting to predict how California will import power and thus to compute a full load-based GHG responsibility confronts two analytic problems: (1) plants outside of California owned by California utilities or under long-term contracts, and (2) short term market purchases that will change in magnitude and source, potentially varying for every single hour of the period under investigation.

The power plants owned by, or under long-term contract, to California LSEs that are located outside of California are readily tracked in PROSYM. In this study, these are called remote power plants, and their characteristics can be readily mapped into a group for reporting purposes. Some of these plants are owned by multiple entities, and these shares of ownership or contract shares are attributed to the loads claiming these facilities. Table 5-3 identifies these remote power plants and their location.

A substantial number of power plants located in various transareas generate power that exceeds the loads of that transarea. Hour by hour PROSYM has dispatched these power plants because their variable costs are cheaper than others and transmission capacity exists to move the output to transareas with deficits in that hour. These power plants effectively export from their own locale and provide the imports that one or more other transareas need to satisfy loads. PROSYM has an accounting construct that accumulates these excesses and deficits in each hour for later use in reporting annual imports and exports. The California versus Rest-of-WECC scorecard which reports net imports to California makes use of these results. Appendix C-1 provides these results for the entire Western Interconnection reported as two regions: (1) California, and (2)

Rest-of-WECC. The results aggregated into these two regions form the primary basis for reporting for all of the base and sensitivity cases for each broad thematic scenario.

Table 5-3: Remote Generators Located Outside California

Remote Generator	Transarea Location	Nameplate Capacity (MW)	Percentage Assigned to California
Boardman 1	Northwest	556	14%
Four Corners 4	New Mexico	740	48%
Four Corners 5	New Mexico	740	48%
Hoover (AZ)	Southern Nevada	920	60%
Hoover (NV)	Southern Nevada	920	60%
Intermountain 1	Utah	900	75%
Intermountain 2	Utah	900	75%
Klamath Cogen 1a	COB	250	50%
Klamath Cogen 1b	COB	250	50%
La Rosita (Az 1a)	La Rosita	256	17%
La Rosita (Az 1b)	La Rosita	256	17%
La Rosita (Az 1c)	La Rosita	256	17%
Navajo 1	Arizona	750	21%
Navajo 2	Arizona	750	21%
Navajo 3	Arizona	750	21%
Palo Verde 1	Palo Verde	1314	27%
Palo Verde 2	Palo Verde	1314	27%
Palo Verde 3	Palo Verde	1318	27%
Parker (CA BUREC)	Southern Nevada	120	41%
Reid Gardner 4	Southern Nevada	265	68%
San Juan 3	New Mexico	495	42%
San Juan 4	New Mexico	506	39%

5.4 Transmission System Analyses

Two different forms of transmission analysis (Inter-Zonal and Intra-Zonal) were conducted. The Inter-Zonal analysis consisted of using the PROSYM model to identify any inter-zonal transmission links that experienced a high level of congestion and to quantify the amounts of capacity that would be required to significantly reduce (if not completely mitigate) the congestion. This was done on a case by case basis and resulted in the identification of the inter-zonal transmission capacity increases discussed in Chapter 2 for each of the thematic Cases.

The Intra-Zonal analysis was performed using the PSLF powerflow model and focused on the SCE Area and was done in conjunction with the aging plant retirement assessment for the SCE Area. A limited number of powerflow studies were also performed to identify inter-zonal additions required in the Imperial Irrigation District transarea.

In the inter-zonal analysis for the SCE Area, detailed powerflow studies were performed for both normal and contingency conditions on the transmission system for Cases 1B, 3A, and 4A for three different load levels (2012, 2016, and 2020 1-in-10 peak loads) to identify transmission constraints that would exist within the SCE Area for each Case and to identify potential methods of mitigating these constraints.

5.5 Integrating Analytic Steps

There were several steps in the analysis which involved iterating between resource plan development, production cost assessments, and transmission contingency assessments. Once production cost model results were considered "complete," they were entered into a Microsoft Access database for purposes of developing the quantitative values reported in this report.

5.5.1 Coordinating Between Models

Developing renewables in the locations where resource potential exists for delivery to load may well involve transmission system augmentations different from a conventional generation build out future. In California, a noteworthy example is the multi-segment transmission line to allow for major development of the wind region in the Tehachipis. In terms of the zonal configuration of PROSYM, this transmission line is internal to the CSCE transarea (Southern California) and does not enter into direct PROSYM computations.

A better illustration of this sort of iterative modeling was development of New Mexico wind potential and the need to expand transmission from New Mexico to Arizona transareas. This need was identified in a trial run of Case 4B (high renewables throughout the West) by running PROSYM and observing the degree of predicted congestion on the transfer link between New Mexico and Arizona, and upgrading that transfer capacity to better match the output of the assumed wind resource. Once the upgrade was identified and entered into PROSYM model, Case 4B was run to obtain the final values. There are differences in the dispatch of resources between the draft and final versions of Case 4B.

5.5.2 Results Integration Database

A Microsoft Access database was developed that archived all of the results of the production cost model runs. This database was the source for the detailed display of results attached as Appendices C-1, C-2, D-1, and D-2. The database was also used to generate the values for a large number of variables that scale directly upon fuel consumption or energy output predicted for specific power plants, such as: (1) GHG emissions, (2) criteria pollutant emissions, (3) water consumption.

Carbon emissions require special analysis. For purposes of this study, California's carbon responsibility was considered to have three components:

- Power plants located in state,
- Power plants owned by, or under long term contracts with, California entities located out of state, and
- Market purchases that cannot be readily tied to a specific power plant.

Within California, carbon emissions are computed by multiplying annual fuel consumption values by a plant-specific carbon emission factor to compute the GHG (carbon) emissions for that plant (pounds of carbon per unit of fuel burned). Similarly, remote generation – plants owned by California LSEs located outside of California intended to support California demand – were tracked separately from "imports" into California. Imports defined as short-term market purchases had carbon emissions computed using the annual average resource characteristics of all Rest-of-WECC power plants. California carbon emissions are reported in these three categories – California, remote generation, and imports.

5.6 Sensitivity Assessments

The deterministic analyses of each case fail to recognize numerous uncertainties in macro- and micro-level assumptions. A limited set of alternative analyses were conducted with the same production cost modeling tool. One body of work took the form of sensitivity assessments, in which a single variable was changed compared to the basecase assumptions for each case. Section 5.6.1 describes the alternative fuel price trajectories evaluated for 2009 – 2020, Section 5.6.2 describes a set of "shock" sensitivities just for year 2020, and Section 5.6.3 describes a set of stochastic production cost model runs that were performed in an attempt to provide a sense of probability distribution of key results for two cases. Factors such as peak load variance, fuel price variance, wind production and other variables were evaluated stochastically to assess how the different resource plans performed under stressed conditions, rather than the average conditions assumed in typical production cost runs. All of these alternative sets of analyses were limited by data and project timing, so these should not be considered an exhaustive review of such uncertainties.

5.6.1 Sensitivity of Results to Alternative Fuel Prices

Each of the thematic scenarios (except for Case 2) were evaluated using alternative high and low fuel prices in addition to the basecase fuel price projections. (The basis for these alternative fuel price projections are described in Section 5.7 of this chapter, and in Appendix H-4.) Case 2 was not evaluated in this same manner because it was defined for a different set of sustained fuel prices, and the range from high to low of the prices used for sensitivity assessments were exceeded by the sustained high fuel prices used to generate the scenario in the first place. So the eight thematic scenarios, excluding Case 2, generate 24 cases.

Other than fuel prices, no changes were made to the production cost dataset, so use of the alternative fuel price series creates a calculation of the sensitivity of the results associated with the production cost modeling process, not any costs associated with capital investment. One can perhaps interpret the results in terms of the variability of production costs in aggregate, and production costs per unit of electricity consumed, to a change in operating costs as a result of unexpected fuel prices that were not foreseen in either the development of the resource mix nor in hedging of risk. The alternative fuel prices are shown in Table 5-6 and Figures 5-2 and 5-3 in Section 5.7 of this chapter.

An overview of the results of the sensitivity assessments are shown in Chapter 8, Section 8.3. More detailed results are contained in Appendix C-1.

5.6.2 Sensitivity of Results to Exogenous Shocks

In contrast to systematic differences in long term trajectories, stochastic "shocks" are a single year increase in fuel prices representing a sudden event affecting gas prices for a period of time (e.g., a year), but such a shock is not expected to continue into future years.   Different hydro conditions during a year are also considered "shocks" of the type that would not expect to continue for several years in a row. All cases were tested with three alternative exogenous "shocks" in a selected year (i.e., the year 2020) to discern whether the policy cases are more or less sensitive to these uncertainties as conventional resource plans. The alternatives tested were:

- Fuel price shock such as a hurricane Katrina event temporarily removing a substantial portion of North American gas production capability needing resulting in extremely high prices (assumed to be $20/MMBtu) for one year (2020);
- Historically high hydro-electric generation that would cause system operators to want to significantly back down other generation over the course of the year (i.e., 2020); and
- Historically low hydro-electric generation that might stress the ability of the system to provide replacement energy over the course of an entire year (i.e., 2020).

The hydro generation used in 2020 for normal, high and low hydro conditions (and the basis for the hydro generation levels) is provided in Table 5-4. These are the variations in hydro-electric generation for all of the Western Interconnection. The high generation case using the wet year assumptions is about 48,000 GWh high than the average, while the low case using the dry year is about 42,000 GWh below the average. The monthly patterns of the specific time periods for the wet and dry conditions were used in the simulations.

Table 5-4: Normal, High and Low Hydro-Electric Generation for Overall Western Interconnection

Modeling Year	Hydro Basis	Hydro Condition	Annual Energy (GWh)
2009-2020	Long-Term Average	Normal	246,167
2020	1997	Wet	294,552
2020	2000-2001	Dry	204,071

The results of the "shock" sensitivity assessment for the thematic scenarios is shown in Chapter 8, Section 8.4. More detailed results are provided in Appendix C-2.

5.6.3 Stochastic Performance of the Resource Mix

A stochastic analysis (probabilistic) can provide a number of interesting insights. Because of the extensive computational requirements necessary to perform such a stochastic analysis, only the year 2020 for two of the cases (Case 1 and Case 4B) were analyzed stochastically in this Scenario Project study.

The stochastic analysis can bring understanding about the reliability of the power system by assessing the Loss of Load Probability of the case. Wind and solar without backup (both central station solar concentrating and rooftop PV) suffer from wide variations in output due to weather conditions. California wind generation is negatively correlated with high peak demand because the high pressure inversions during California's summer peak conditions simultaneously create high temperatures and low wind velocity in wind regions that normally have much greater air movement.

Stochastic analysis can also bring better understanding to the volatility in production cost of the case. While wind and solar suffer from wide variation in output, such technologies are not subject to possible changes in natural gas prices.

In Cases 1 and 4B, the stochastic capabilities of the model were used to determine the reliability and variability of power cost of the assumed resource mix. This stochastic analysis involved 100 iterations of all hours of the year 2020 in these two cases. The analysis involved Monte Carlo draws on the following variables:

- Natural gas prices;
- Daily loads in each transarea (The method assumes a mean reversion of these draws back toward normal. It also assumes historical correlation of load variations between transareas.);
- Unit outages;
- Weekly hydro conditions were performed, with the statistical parameters carefully designed to assure that the envelope of resulting hydro conditions over the 100 iterations closely represents historical range of monthly and annual hydro conditions; and
- Daily wind and solar patterns. The wind draws were separately processed to represent that low wind days are likely to occur on days with extremely high loads.

Results of the stochastic analysis are reported in Chapter 8, Section 8.5.

5.6.4 Summary of Sensitivity Case Assessments

Table 5-5 provides an overview of the cases that were assessed in a deterministic sense using basecase values, and in the sensitivity and stochastic sense using alternative fuel prices, various shock variables, and statistically significant probability assessments.

Table 5-5: Summary of Cases Assessed

Thematic Scenario	Fuel Price Sensitivities	Physical Performance Sensitivities	Evaluation and/or Side Analyses
1A – Current Conditions	Reference case with high (P75) and low (P25) alternatives 2009-2020	2020 deviations: - Gas price spike - High hydro - Low hydro	Stochastic assessment performed on this case
1B – Current Requirements	Reference case with high (P75) and low (P25) alternatives 2009-2020	2020 deviations: - Gas price spike - High hydro - Low hydro	
2 – Sustained High Gas Prices	Assumed $10/mmbtu gas price used to develop resource plan		Can be used to ascertain how utility decision-makers might have shifted resource mix with knowledge of high fuel prices
3A – High EE in California only	Reference case with high (P75) and low (P25) alternatives 2009-2020	2020 deviations: - Gas price spike - High hydro - Low hydro	
3B – High EE in both California and Rest-of-WECC	Reference case with high (P75) and low (P25) alternatives 2009-2020	2020 deviations: - Gas price spike - High hydro - Low hydro	This case has been used by Global Gas to develop low UEG impacts on natural gas price methodology
4A- High Renewables in California only	Reference case with high (P75) and low (P25) alternatives 2009-2020	2020 deviations: - Gas price spike - High hydro - Low hydro	
4B – High Renewables in both California and Rest-of-WECC	Reference case with high (P75) and low (P25) alternatives 2009-2020	2020 deviations: - Gas price spike - High hydro - Low hydro	Stochastic assessment performed on this case
5A- High EE and Renew in California only	Reference case with high (P75) and low (P25) alternatives 2009-2020	2020 deviations: - Gas price spike - High hydro - Low hydro	
5B- High EE and Renew in both California and Rest-	Reference case with high (P75) and low (P25) alternatives	2020 deviations: - Gas price spike - High hydro	This case will be the final one used by Global Gas for evaluating low UEG impacts

Thematic Scenario	Fuel Price Sensitivities	Physical Performance Sensitivities	Evaluation and/or Side Analyses
of-WECC	2009-2020	- Low hydro	on natural gas prices (using meth. for Case 3B)

5.7 Alternative Fuel Price Cases

Financial comparison of the policy cases to determine incremental costs or incremental savings of the preferred resource types are sensitive to different fuel price forecasts, including crude oil, natural gas, and coal. Global Energy conducted several assessments for the Energy Commission to support this project. This section discusses:

- Why fuel price forecasts are fundamental to the conclusions of the IEPR scenario analysis;
- Why fuel forecasting involves both scenario and probability analysis
- Why crude oil, natural gas, coal and other fuel prices are inter-related and must be considered together
- What fuel price forecast scenarios have been considered and what are their results

5.7.1 Background

After a fossil-fuel fired electricity generation facility (such as a coal plant or natural-gas fired combined cycle plant) has been constructed, the majority of its costs to produce electricity are attributable to fuel. Therefore, the fuel price forecasts, key inputs into the Market Analytics model, are fundamental to the conclusions of the study.

Energy price forecasting over a long time horizon is inherently risky. The primary reasons are that the governing fundamental factors (such as supply and demand) are numerous and intrinsically subject to forces and factors that together force consideration of uncertainty.

Adding to the uncertainties of the fundamental factors are the non-fundamental factors that add volatility and exert varying degrees of influence on long-term trends. Non-fundamental factors include the fears and market perceptions of both large commercial buyers and of speculators, which increasingly are the result of international geopolitical factors.

Because of these successive layers of uncertainty, this study was designed from the beginning to address them in some manner. While there are many approaches, one method of fuel price forecasting involves the careful identification of several alternative scenarios that reflect alternative views of an uncertain future. Given the timeframe and other objectives of this project, other methods were not explored as alternatives to scenario forecasting for fuel prices. For this study, the scenarios to be considered were defined by a study team comprising Energy Commission staff and consultants.

Even after scenarios have been defined, fuel forecasting involves the consideration of probabilities of a large array of short term events such as hurricanes, sustained Arctic fronts, or major pipeline disruptions that may impact fuel prices of a given scenario. So the fuel forecasting applied in this study involves scenario analysis as well as probabilistic (stochastic) analysis. In this way, a wider range of uncertainties was considered than if just scenario assessments had been conducted.

The fuel forecasts involved crude oil, natural gas, and coal. These forecasts cannot be carried out in isolation from one another. As world energy markets become ever more integrated through advancing globalization, the prices of these three important energy fuels are increasingly interdependent even though they may not be considered as substitutes for one another in electricity generation. Though each fuel responds to fundamental factors specific to that fuel, there are also economic links among the three related to inter-fuel competition, such as the growing use of Liquefied Natural Gas (LNG), a globally transported fuel commonly priced through formulas related to crude oil prices.

Another close link between oil and natural gas markets is in the manufacturing sector, where fuel switching occurs to the extent permitted by environmental regulations when either fuel (natural gas or oil-derived products such as diesel) become significantly less expensive on a per-MMBtu basis.

A third example in the increasing interrelationship of energy commodity prices is the growing use by commercial as well as non-commercial entities (risk-averse "hedgers" and "speculators", respectively) of futures and derivatives markets. Trading on the same platforms and in the same venues, both regulated such as NYMEX and non-regulated such as the Over The Counter (OTC) markets, crude oil, oil-derived products such as diesel, natural gas, and coal respond to increasingly integrated market perceptions of scarcity and abundance. Thus, events triggering price increases or decreases in one commodity commonly carry over to others, with one commodity commonly leading others upward or downward in the futures markets. For example, the natural gas futures market commonly moves in "sympathy" with crude oil markets and then indirectly influences the daily coal Over the Counter (OTC) market. These fuel interrelationships have been taken into account in the alternative fuel price cases produced by Global Energy Decisions' integrated fuel team of consultants qualified in the pricing of crude oil, LNG, coal, and natural gas.

The natural gas forecasts are prepared using GPCM®, a natural gas model of the North American natural gas system, licensed to Global Energy Decisions by its owner the Robert Brooks and Associates Company. Appendix H-1 is a description of GPCM® and its physical infrastructure. Crude oil prices are a key input to GPCM®.

The coal forecasts are prepared by Global Energy Decisions' coal analytics group using a proprietary coal forecast model that also incorporates a natural gas forecast and indirectly a crude oil forecast, as well as extensive input regarding the fundamentals of the North American coal industry.

5.7.2 Stochastic Fuel Forecasts

Stochastic (probabilistic) modeling was performed around the basecase price forecasts for natural gas and coal. (Preparation of basecase prices is discussed in Appendix H-2.) Such a stochastic analysis does not involve an entirely new scenario with new fundamental inputs, but rather simulates the purely mathematical results of price events of greater or lesser magnitude that may provide shocks within a given scenario. For this analysis, historic variability in prices was assumed to continue, centered around the basecase price forecast. This analysis is performed on Global Energy Decisions' Planning and Risk ™ energy market modeling tool. The methodology and formulae by which this modeling is performed is explained in Appendix H-4.

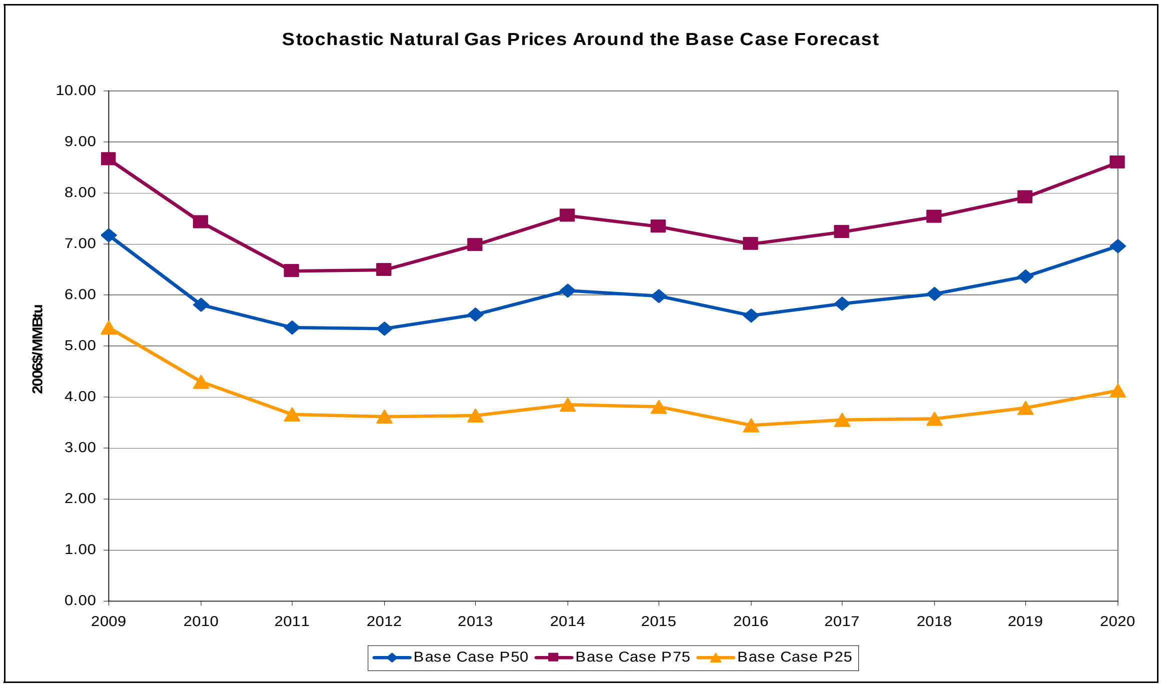
Illustrating this concept, referring to Table 5-6, the basecase Fuel Forecast represents the most likely probability (the mean, or P_{50}). Other prices are assigned probabilities from 1 to 49 and 51 to 99. The P_{25} price, for example, represents a relatively low price at which the probability is 75 percent that the price will be higher and only 25 percent that the price will be lower. Conversely, the P_{75} price is a relatively high price (compared to the basecase Forecast price) at which there is only a 25 percent chance that the price will be higher, and a 75 percent chance that the price will be lower. P_{50} (Base), P_{25}, and P_{75} forecasts are shown in Figures 5-2 and 5-3.

Global Energy's modeling produces a wide range of these stochastic price projections. The scenario project team chose to use the P_{25} and P_{75} series, thus covering about 50 percent of the total variation expected based on historic volatility.

Table 5-6: Stochastic Fuel Forecasts ($2006)

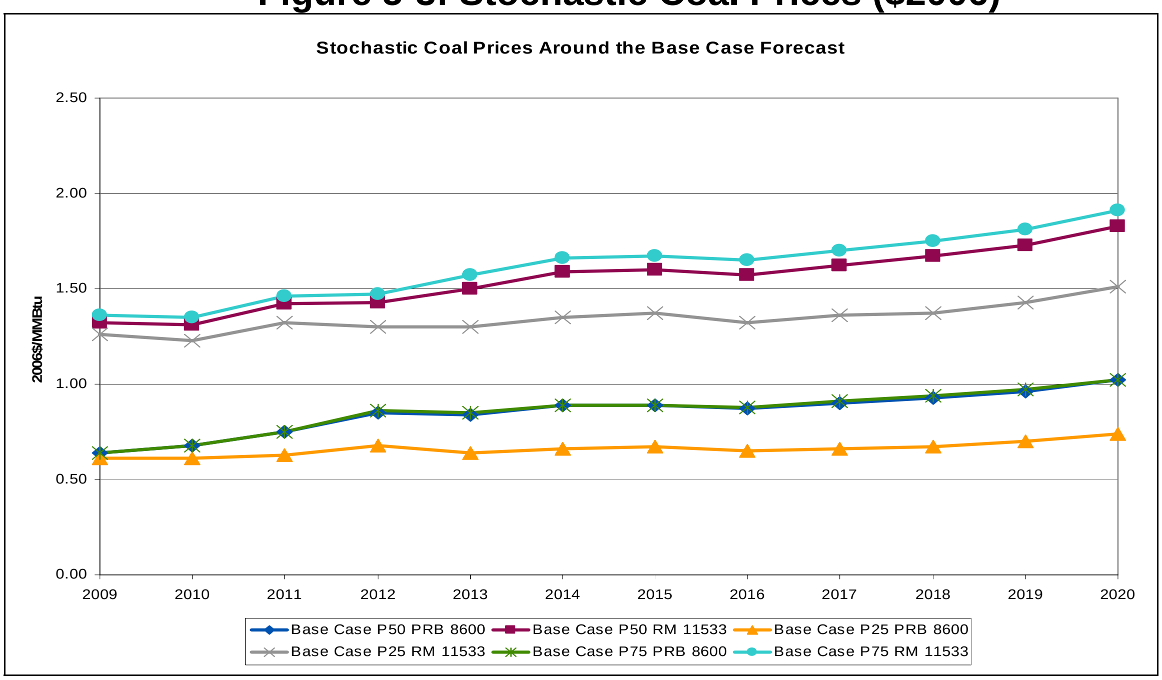
	Henry Hub Natural Gas Forecasts ($2006/mmbtu)			Coal Forecasts ($2006/mmbtu)					
Year	Base Case P50	Base Case P75	Base Case P25	Base		P25		P75	
				PRB 8600	RM 11533	PRB 8600	RM 11533	PRB 8600	RM 11533
1/1/2009	7.17	8.66	5.36	0.64	1.32	0.61	1.26	0.64	1.36
1/1/2010	5.82	7.42	4.29	0.68	1.31	0.61	1.23	0.68	1.35
1/1/2011	5.36	6.47	3.66	0.75	1.42	0.63	1.32	0.75	1.46
1/1/2012	5.34	6.48	3.61	0.85	1.43	0.68	1.30	0.86	1.47
1/1/2013	5.61	6.98	3.63	0.84	1.50	0.64	1.30	0.85	1.57
1/1/2014	6.09	7.56	3.85	0.89	1.59	0.66	1.35	0.89	1.66
1/1/2015	5.99	7.35	3.81	0.89	1.60	0.67	1.37	0.89	1.67
1/1/2016	5.60	6.99	3.45	0.87	1.57	0.65	1.32	0.88	1.65
1/1/2017	5.83	7.24	3.56	0.90	1.62	0.66	1.36	0.91	1.70
1/1/2018	6.02	7.54	3.57	0.93	1.67	0.67	1.37	0.94	1.75
1/1/2019	6.36	7.91	3.79	0.96	1.73	0.70	1.43	0.97	1.81
1/1/2020	6.96	8.60	4.12	1.02	1.83	0.74	1.51	1.02	1.91

Figure 5-2: Stochastic Natural Gas Prices ($2006)



Source: Global Energy

Figure 5-3: Stochastic Coal Prices ($2006)



Source: Global Energy

5.7.3 Scenario-Based Fuel Price Forecasts

Three fuel forecasts (see Table 5-5 and Figures 5-4 and 5-5), all in 2006 dollars, have been prepared for the time horizon 2009-2020. As discussed in Section 5.7.1 of this chapter, each of these represents a scenario developed with a specific set of conditions in mind.

5.7.3.1 Basecase Fuel Price Forecast

The basecase fuel price forecast was prepared by Global in December 2006 – January 2007, beginning from Global Energy's Fall 2006 Reference Case, but modified by project team decisions for this project. (See Appendix H-2) Its basic elements are:

- Outlook broadly similar to the EIA 2007 AEO forecast (but see Appendix H-2 for a comparison of the methodologies of EIA versus GPCM®)
- Crude oil: the EIA 2007 Annual Energy Outlook forecast for Imported Low-Sulfur Light Crude Oil
- Natural Gas: Global Energy's December, 2006 Reference Case, very similar to EIA's 2007 AEO natural gas forecast after substitution of the EIA 2007 crude oil forecast.
- Coal: Global Energy's Fall 2006 Coal Reference Case for WECC power plants (PRB 8600 Btu/lb coal and Rockies 11,533 Btu/lb coal are shown in the accompanying table and figures).

5.7.3.2 Sustained Scarcity Fuel Price Forecast

A sustained scarcity fuel price forecast was developed in February 2007 for use in developing Case 2 of this scenario project. The premise of this scenario is that fuel prices rise to a high level that is sustainable for many years, and the question of interest is how utility executives might choose a different resource mix through time in response to these sustained high fuel prices. (see Appendix H-3) Its basic elements are:

- Outlook assumes sustained scarcity of U.S. indigenous natural gas production, accompanied by high oil and coal prices
- Crude Oil: $75-$85/Bbl
- Natural gas:
  - Accelerated decline in Lower 48 production, dropping 2 percent per year below the Base Case to 13.0 Tcf/year by 2020, as compared to 19.3 Tcf in 2020 for the Base Case. (Lower 48 production is approximately 16 Tcf in 2010.)
  - The ANS pipeline and the McKenzie Delta pipeline are not built during the forecast horizon of 2009-2020.
  - LNG provides the incremental supply and North America regasification facilities are utilized at a high regas capacity utilization percentage.
- Coal: Using the Scarcity High Gas Price, the Global Energy proprietary model forecasts the prices for coal types delivered to coal-fired power plants in WECC.

5.7.3.3 Low Consumption Fuel Forecast

Since this project intuitively generates low projections for natural gas consumption for power generation, a feature of the project design has been to investigate the impacts of such decreases in demand on natural gas market clearing prices. The ultimate objective is to determine whether these effects, addressed by previous studies of high renewable futures, are significant and whether modeling techniques exist to devise a credible estimate.

The basic approach being undertaken by Global Energy gas team is described in Appendix H-5. Its basic elements are:

- Outlook: Scenario Project Case 3B - high energy efficiency usage
- Crude oil: no change from the basecase crude oil forecast
- Natural gas: natural gas demand data for electricity generation from Case 3B (High Energy Efficiency throughout WECC) were inserted as replacement data into the basecase gas model. These values represent a drop of 39 percent in demand for power generation by 2020, as compared to the Base Case, for the entire Western Interconnection. Other sectors of demand for natural gas, i.e., Residential, Commercial, and Industrial, in the West are not changed from their values in the basecase. Demand for natural gas in all other regions is kept the same as in the basecase.
- Coal: no change from the basecase forecast

The low natural gas prices reported in Table 5-7 and Figure 5-4 for natural gas prices are preliminary and subject to change. As is also noted in Chapter 8, Section 8.3, further work with other scenario project cases is underway, and further documentation of methods and results is forthcoming.

Table 5-7: Basecase, Sustained Scarcity, and Low Consumption Fuel Forecasts ($2006)

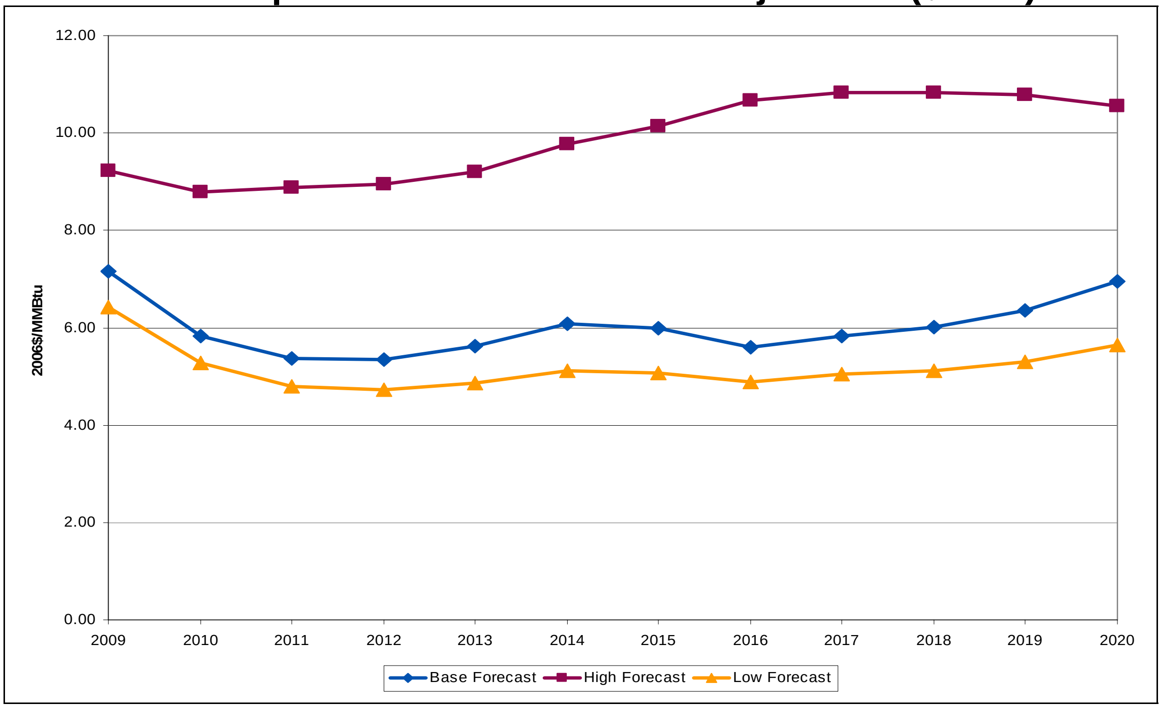
	Basecase Fuel Forecast				Sustained Scarcity Fuel Forecast				Low Consumption Fuel Forecast			
Year	Crude Oil $/Bbl	Natural Gas $/MMBtu	Coal $/MMBtu		Crude Oil $/bbl	Natural Gas $/MMBtu	Coal $/MMBtu		Crude Oil $/bbl	Natural Gas $/MMBtu	Coal $/MMBtu	
			PRB	Rockies			PRB	Rockies			PRB	Rockies
2009	62.77	7.17	0.64	1.32	75.00	9.23	0.64	1.36	62.77	6.42	0.64	1.32
2010	59.23	5.82	0.68	1.31	73.72	8.78	0.69	1.37	59.23	5.28	0.68	1.31
2011	56.00	5.36	0.75	1.42	72.46	8.88	0.76	1.49	56.00	4.80	0.75	1.42
2012	53.30	5.34	0.85	1.43	71.22	8.94	0.87	1.51	53.30	4.72	0.85	1.43
2013	51.52	5.61	0.84	1.50	70.00	9.20	0.87	1.61	51.52	4.86	0.84	1.50
2014	51.16	6.09	0.89	1.59	71.97	9.78	0.91	1.70	51.16	5.12	0.89	1.59
2015	51.40	5.99	0.89	1.60	73.99	10.13	0.91	1.73	51.40	5.08	0.89	1.60
2016	51.27	5.60	0.87	1.57	76.07	10.66	0.91	1.72	51.27	4.89	0.87	1.57
2017	52.35	5.83	0.90	1.62	78.21	10.82	0.94	1.77	52.35	5.05	0.90	1.62
2018	52.85	6.02	0.93	1.67	80.41	10.84	0.97	1.81	52.85	5.11	0.93	1.67
2019	53.54	6.36	0.96	1.73	82.67	10.78	1.00	1.88	53.54	5.30	0.96	1.73
2020	53.64	6.96	1.02	1.83	85.00	10.55	1.06	1.97	53.64	5.64	1.02	1.83

Natural Gas: Henry Hub forecasts as explained in text

Coal: Powder River Basin (8600 Btu/lb) and Rocky Mountains (11,533), Global Energy Decision

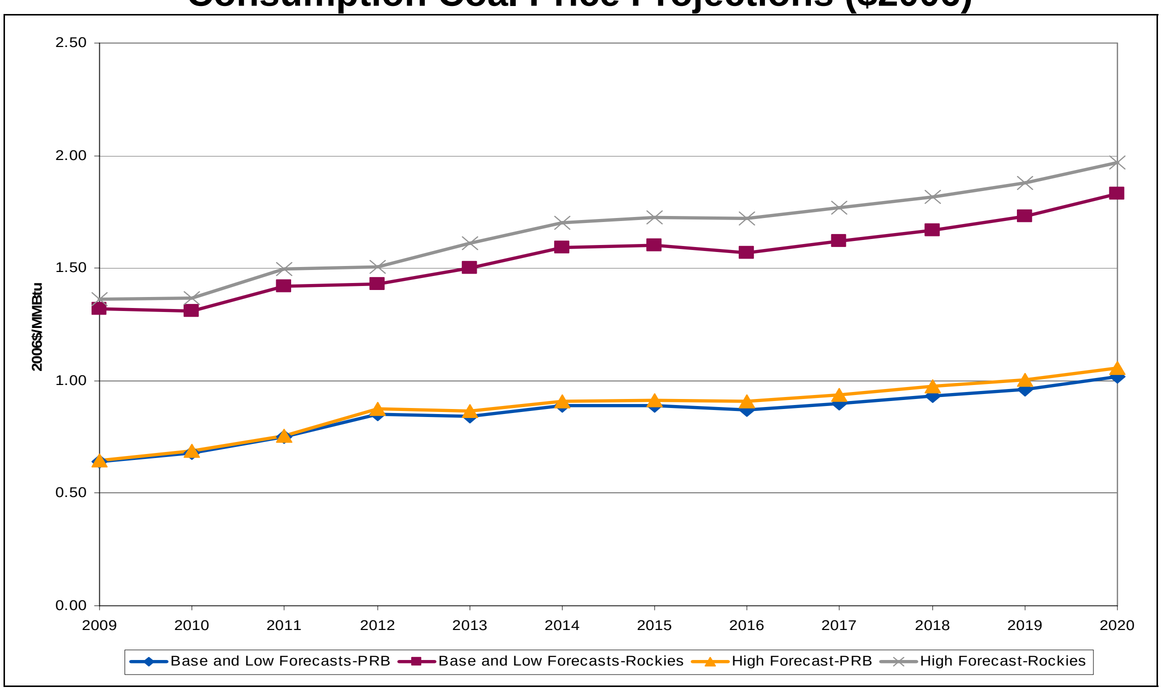
Crude Oil: Base and Low = EIA AEO 2007 Imported Low-Sulfur (WTI proxy); High = Global Energy Decisions

Figure 5-4: Basecase, Sustained Scarcity, and Low Consumption Natural Gas Price Projections ($2006)



Source: Global Energy

Figure 5-5: Basecase, Sustained Scarcity, and Low Consumption Coal Price Projections ($2006)



Source: Global Energy

CHAPTER 6: DETERMINISTIC ASSESSMENT RESULTS

This chapter provides the results of the analyses of the more than 50 cases that were modeled. Section 6.1 provides an overview of the numeric specifications for each production cost dataset in greater detail than Table 2.1 of Chapter 2. Global devised two "scorecard" formats to compare and contrast the results of the model runs across the various keys for certain key variables. A transareas results scorecard provides physical loads and generation and associated characteristics for each of the 25 transareas covering the West. A geographically aggregated scorecard shows results for California and Rest-of-WECC to more readily communicate the overall results. This latter format is also used to summarize cost implications that cannot be readily allocated to specific transareas.

Sections 6.2 and 6.3 provide overviews of the numeric results more readily digested than the very detailed results of Appendices 3 and 4.

6.1 Overview of Cases as Modeled

This subsection provides an overview of the resource mix in capacity terms, supply demand/balance adjusting for demand-side measures revising loads and sales, and key energy inputs for each Case. Its focus is on being descriptive from a traditional resource planning perspective.   The following is a list of the cases along with a brief description of each one's broad theme:

- Case 1-Current Conditions. Utilities fall short of their goals.
- Case 1B-Current Requirements. Utilities meet statutory goals.
- Case 2-Sustained High Gas Prices.
- Case 3A-High Energy Efficiency in California only.
- Case 3B-High Energy Efficiency in California and the Rest-of-WECC.
- Case 4A-High Renewables in California only.
- Case 4B-High Renewables in California and the Rest-of-WECC.
- Case 5A-High Energy Efficiency and Renewables in California only.
- Case 5B-High Energy Efficiency and Renewables in California and the Rest-of-WECC.

Tables 6-1 through 6-9 present the load and resource balance for California and the Rest-of-WECC for the summer peak.

Table 6-1: Load and Resource Balance, Summer Peak Case 1-Current Conditions (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	0	0	0	0	0	0	0
PV Rooftop	0	0	0	0	0	0	0
Adjusted Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	271	271	271	271	271	271	271
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	272	272	272	272	272	272	272
Demand Response	1,808	1,808	1,808	1,808	1,808	1,808	1,808
Geothermal	2,339	2,339	2,339	2,339	2,339	2,339	2,339
Natural Gas	39,972	42,732	42,103	41,554	42,572	42,770	43,447
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	919	949	1,037	1,111	1,186	1,260	1,336
Resource Total	65,104	67,894	67,353	66,878	67,972	68,226	68,979
Reserve Margin	12%	15%	11%	7%	7%	4%	3%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	0	0	0	0	0	0	0
PV Rooftop	0	0	0	0	0	0	0
Adjusted Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	132	132	132	132	132	132	132
Coal	37,032	38,073	40,323	40,293	41,245	42,735	44,149
Concentrating Solar Power	76	76	76	76	76	76	76
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,062	1,152	1,152	1,152	1,152	1,152	1,152
Natural Gas	43,364	44,354	46,311	50,623	56,363	61,314	65,234
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,175	2,451	2,955	3,477	3,982	4,495	4,997
Resource Total	144,229	146,714	151,968	156,803	164,100	171,045	176,881
Reserve Margin	47%	45%	44%	42%	42%	42%	41%

Table 6-2: Load and Resource Balance, Summer Peak
Case 1B-Current Requirements (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	624	1,201	2,276	3,384	4,386	5,345	6,312
PV Rooftop	47	57	121	185	249	259	270
Adjusted Load	57,710	57,901	58,383	58,742	59,088	59,685	60,321
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	316	341	516	566	581	581	581
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	362	368	722	1,445	1,494	1,501	1,509
Demand Response	2,925	3,094	3,224	3,286	3,350	3,357	3,357
Geothermal	2,354	2,389	2,654	2,864	2,864	2,880	2,896
Natural Gas	38,932	41,192	40,563	39,494	39,232	37,950	36,747
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	975	1,007	1,412	1,887	1,939	1,997	2,056
Resource Total	65,387	67,915	68,615	69,065	68,984	67,772	66,652
Reserve Margin	13%	17%	18%	18%	17%	14%	10%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	0	0	0	0	0	0	0
PV Rooftop	23	46	72	99	105	118	136
Adjusted Load	98,323	100,802	105,533	110,463	115,262	120,202	125,378
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	279	333	556	731	879	880	880
Coal	37,032	38,073	39,823	39,793	40,745	42,235	43,649
Concentrating Solar Power	226	255	336	398	465	518	574
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,265	1,523	1,745	1,841	1,994	2,020	2,049
Natural Gas	43,192	44,202	45,839	50,291	55,491	60,882	64,662
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,581	2,697	2,994	3,296	3,713	3,835	3,953
Resource Total	144,963	147,559	152,313	157,400	164,438	171,511	176,907
Reserve Margin	47%	46%	44%	42%	43%	43%	41%

Table 6-3: Load and Resource Balance, Summer Peak Case 2-Sustained High Gas Prices (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	780	1,551	3,092	4,627	6,176	7,692	9,221
PV Rooftop	0	0	0	0	0	0	0
Adjusted Load	57,601	57,607	57,688	57,684	57,547	57,597	57,682
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	272	272	272	272	272	272	272
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	272	272	272	272	272	272	272
Demand Response	1,808	1,808	1,808	1,808	1,808	1,808	1,808
Geothermal	2,340	2,340	2,340	2,340	2,340	2,340	2,340
Natural Gas	38,932	41,192	40,563	39,494	39,432	37,690	36,267
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	919	949	1,037	1,111	1,186	1,260	1,336
Resource Total	64,066	66,356	65,815	64,820	64,834	63,148	61,801
Reserve Margin	11%	15%	14%	12%	13%	10%	7%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	650	1,300	2,603	3,902	5,204	6,509	7,815
PV Rooftop	0	0	0	0	0	0	0
Adjusted Load	97,696	99,548	103,002	106,660	110,163	113,811	117,699
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	132	132	132	132	132	132	132
Coal	37,032	38,073	40,323	40,293	41,245	43,235	44,649
Concentrating Solar Power	76	76	76	76	76	76	76
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,062	1,152	1,152	1,152	1,152	1,152	1,397
Natural Gas	43,164	43,914	45,031	48,503	52,823	56,124	58,879
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,175	2,451	2,955	3,477	3,982	4,495	4,997
Resource Total	144,029	146,274	150,688	154,683	160,560	166,355	171,271
Reserve Margin	47%	47%	46%	45%	46%	46%	46%

Table 6-4: Load and Resource Balance, Summer Peak Case 3A-High Energy Efficiency in California Only (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	780	1,551	3,092	4,627	6,176	7,692	9,221
PV Rooftop	47	57	121	185	249	259	270
Adjusted Load	57,553	57,550	57,567	57,499	57,298	57,338	57,413
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	316	341	516	566	581	581	581
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	362	368	722	1,445	1,494	1,501	1,509
Demand Response	2,925	3,137	3,422	3,639	3,859	4,057	4,057
Geothermal	2,354	2,389	2,654	2,864	2,864	2,880	2,896
Natural Gas	38,932	41,192	40,563	39,274	38,692	37,410	36,207
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	975	1,007	1,412	1,887	1,939	1,997	2,056
Resource Total	65,387	67,957	68,812	69,198	68,953	67,932	66,812
Reserve Margin	14%	18%	20%	20%	20%	18%	16%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	0	0	0	0	0	0	0
PV Rooftop	23	46	72	99	105	118	136
Adjusted Load	98,323	100,802	105,533	110,463	115,262	120,202	125,378
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	279	333	556	731	879	880	880
Coal	37,032	38,073	39,823	39,793	40,745	42,235	43,649
Concentrating Solar Power	226	255	336	398	465	518	574
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,265	1,523	1,745	1,841	1,994	2,020	2,049
Natural Gas	43,192	44,202	45,839	50,291	55,491	60,882	64,662
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,581	2,697	2,994	3,296	3,713	3,835	3,953
Resource Total	144,963	147,559	152,313	157,400	164,438	171,511	176,907
Reserve Margin	47%	46%	44%	42%	43%	43%	41%

Table 6-5: Load and Resource Balance, Summer Peak Case 3B-High Energy Efficiency in California and Rest-of-WECC (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	780	1,551	3,092	4,627	6,176	7,692	9,221
PV Rooftop	47	57	121	185	249	259	270
Adjusted Load	57,553	57,550	57,567	57,499	57,298	57,338	57,413
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	316	341	516	566	581	581	581
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	362	368	722	1,445	1,494	1,501	1,509
Demand Response	2,925	3,137	3,422	3,639	3,859	4,057	4,057
Geothermal	2,354	2,389	2,654	2,864	2,864	2,880	2,896
Natural Gas	38,932	41,192	40,563	39,254	38,672	37,390	36,187
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	975	1,007	1,412	1,887	1,939	1,997	2,056
Resource Total	65,387	67,957	68,812	69,178	68,933	67,912	66,792
Reserve Margin	14%	18%	20%	20%	20%	18%	16%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	1,430	2,860	5,726	8,583	11,450	14,321	17,194
PV Rooftop	23	46	72	99	105	118	136
Adjusted Load	96,894	97,942	99,807	101,880	103,812	105,882	108,184
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	279	333	556	731	879	880	880
Coal	37,032	38,073	39,523	39,493	40,445	41,935	42,849
Concentrating Solar Power	226	255	336	398	465	518	574
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,265	1,523	1,745	1,841	1,994	2,020	2,049
Natural Gas	42,592	43,062	43,699	46,051	49,151	51,382	53,902
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,581	2,697	2,994	3,296	3,713	3,835	3,953
Resource Total	144,363	146,419	149,873	152,860	157,798	161,711	165,347
Reserve Margin	49%	49%	50%	50%	52%	53%	53%

Table 6-6: Load and Resource Balance, Summer Peak Case 4A-High Renewables in California Only (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	624	1,201	2,276	3,384	4,386	5,345	6,312
PV Rooftop	154	195	849	1,503	2,157	2,244	2,335
Adjusted Load	57,604	57,763	57,654	57,424	57,180	57,700	58,256
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	317	342	461	660	859	1,057	1,256
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	330	330	590	1,108	1,626	2,142	2,659
Demand Response	2,925	3,094	3,224	3,286	3,350	3,357	3,357
Geothermal	2,354	2,389	2,703	3,162	3,622	4,081	4,564
Natural Gas	38,932	41,192	40,563	39,054	37,532	35,290	33,047
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	975	1,007	1,359	1,975	2,591	3,207	3,824
Resource Total	65,356	67,878	68,424	68,768	69,104	68,640	68,212
Reserve Margin	13%	18%	19%	20%	21%	19%	17%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	0	0	0	0	0	0	0
PV Rooftop	23	46	72	99	105	118	136
Adjusted Load	98,323	100,802	105,533	110,463	115,262	120,202	125,378
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	279	333	556	731	879	880	880
Coal	37,032	38,073	39,823	39,793	40,745	42,235	43,649
Concentrating Solar Power	226	255	336	398	465	518	574
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,265	1,523	1,745	1,841	1,994	2,020	2,049
Natural Gas	43,192	44,202	45,839	50,291	55,491	60,882	64,662
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,581	2,697	2,994	3,296	3,713	3,835	3,953
Resource Total	144,963	147,559	152,313	157,400	164,438	171,511	176,907
Reserve Margin	47%	46%	44%	42%	43%	43%	41%

Table 6-7: Load and Resource Balance, Summer Peak
Case 4B-High Renewables in California and Rest-of-WECC (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	624	1,201	2,276	3,384	4,386	5,345	6,312
PV Rooftop	154	195	849	1,503	2,157	2,244	2,335
Adjusted Load	57,604	57,763	57,654	57,424	57,180	57,700	58,256
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	317	342	461	660	859	1,057	1,256
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	330	330	590	1,108	1,626	2,142	2,659
Demand Response	2,925	3,094	3,224	3,286	3,350	3,357	3,357
Geothermal	2,354	2,389	2,703	3,162	3,622	4,081	4,564
Natural Gas	38,932	41,192	40,563	39,054	37,532	35,290	33,047
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	975	1,007	1,359	1,975	2,591	3,207	3,824
Resource Total	65,356	67,878	68,424	68,768	69,104	68,640	68,212
Reserve Margin	13%	18%	19%	20%	21%	19%	17%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	0	0	0	0	0	0	0
PV Rooftop	23	46	72	99	105	118	136
Adjusted Load	98,323	100,802	105,533	110,463	115,262	120,202	125,378
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	279	333	556	731	879	880	880
Coal	37,032	38,073	39,823	39,793	40,745	42,235	43,649
Concentrating Solar Power	226	255	336	398	465	518	574
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,265	1,523	1,745	1,841	1,994	2,020	2,049
Natural Gas	43,192	44,202	45,839	50,291	55,491	60,882	64,662
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,581	2,697	2,994	3,296	3,713	3,835	3,953
Resource Total	144,963	147,559	152,313	157,400	164,438	171,511	176,907
Reserve Margin	47%	46%	44%	42%	43%	43%	41%

Table 6-8: Load and Resource Balance, Summer Peak Case 5A-High Energy Efficiency and Renewables California Only (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	780	1,551	3,092	4,627	6,176	7,692	9,221
PV Rooftop	154	195	849	1,503	2,157	2,244	2,335
Adjusted Load	57,447	57,412	56,839	56,181	55,390	55,352	55,347
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	317	342	461	660	859	1,057	1,256
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	330	330	590	1,108	1,626	2,142	2,659
Demand Response	2,925	3,137	3,422	3,639	3,859	4,057	4,057
Geothermal	2,354	2,389	2,703	3,162	3,622	4,081	4,564
Natural Gas	38,932	41,192	40,563	39,054	37,532	35,290	33,047
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	975	1,007	1,359	1,975	2,591	3,207	3,824
Resource Total	65,356	67,920	68,622	69,122	69,613	69,341	68,913
Reserve Margin	14%	18%	21%	23%	26%	25%	25%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	0	0	0	0	0	0	0
PV Rooftop	23	46	72	99	105	118	136
Adjusted Load	98,323	100,802	105,533	110,463	115,262	120,202	125,378
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	279	333	556	731	879	880	880
Coal	37,032	38,073	39,823	39,793	40,745	42,235	43,649
Concentrating Solar Power	226	255	336	398	465	518	574
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,265	1,523	1,745	1,841	1,994	2,020	2,049
Natural Gas	43,192	44,202	45,839	50,291	55,491	60,882	64,662
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,581	2,697	2,994	3,296	3,713	3,835	3,953
Resource Total	144,963	147,559	152,313	157,400	164,438	171,511	176,907
Reserve Margin	47%	46%	44%	42%	43%	43%	41%

Table 6-9: Load and Resource Balance, Summer Peak Case 5B-High Energy Efficiency and Renewables in California and the Rest-of-WECC (MW)

	2009	2010	2012	2014	2016	2018	2020
California							
Load	58,381	59,158	60,780	62,311	63,723	65,289	66,903
Energy Efficiency	780	1,551	3,092	4,627	6,176	7,692	9,221
PV Rooftop	155	196	852	1,508	2,164	2,251	2,342
Adjusted Load	57,446	57,411	56,836	56,176	55,383	55,345	55,340
Resources							
Hydro	10,237	10,237	10,237	10,237	10,237	10,237	10,237
Pumped Storage	3,355	3,355	3,355	3,355	3,355	3,355	3,355
Biomass	317	342	461	660	859	1,057	1,256
Coal	415	415	415	415	415	415	415
Concentrating Solar Power	329	329	587	1,103	1,619	2,135	2,651
Demand Response	2,925	3,137	3,422	3,639	3,859	4,057	4,057
Geothermal	2,354	2,389	2,703	3,162	3,622	4,081	4,564
Natural Gas	38,932	41,192	40,563	39,054	37,532	35,290	33,047
Nuclear	4,480	4,480	4,480	4,480	4,480	4,480	4,480
Oil	345	345	345	345	345	327	327
Other	693	693	693	693	693	693	693
Wind	975	1,007	1,359	1,975	2,591	3,207	3,824
Resource Total	65,355	67,919	68,619	69,117	69,606	69,333	68,905
Reserve Margin	14%	18%	21%	23%	26%	25%	25%
Rest-of-WECC							
Load	98,346	100,848	105,605	110,562	115,367	120,320	125,514
Energy Efficiency	1,430	2,860	5,726	8,583	11,450	14,321	17,194
PV Rooftop	28	56	95	146	188	241	391
Adjusted Load	96,888	97,931	99,785	101,833	103,729	105,758	107,928
Resources							
Hydro	52,170	52,260	52,801	52,828	52,938	52,938	52,938
Pumped Storage	771	771	771	771	771	771	771
Biomass	279	333	587	764	941	1,102	1,265
Coal	37,032	38,073	39,523	39,493	39,945	40,435	40,849
Concentrating Solar Power	226	255	460	723	987	1,250	1,513
Demand Response	1,009	1,007	1,010	1,014	1,014	1,014	1,014
Geothermal	1,265	1,523	1,874	2,243	2,713	3,095	3,496
Natural Gas	42,652	43,062	43,319	44,071	45,751	47,302	48,222
Nuclear	5,068	5,068	5,068	5,068	5,068	5,068	5,068
Oil	371	371	371	371	361	351	351
Other	999	999	999	999	999	999	999
Wind	2,581	2,697	3,517	4,894	6,257	7,610	8,957
Resource Total	144,423	146,419	150,298	153,239	157,744	161,935	165,443
Reserve Margin	49%	50%	51%	50%	52%	53%	53%

6.2 Geographically Aggregated Results

This section aggregates the production cost model results for the 29 transareas to two regions: (1) California, and (2) Rest-of-WECC. Thus, this section provides an overview of the California consequences for each Case. Tables and graphs abstract results from the CA vs. Rest-of-WECC scorecards, a portion of which will be in Appendix C-1, while the full scorecard will be available to download from the Energy Commission website. The CA vs Rest-of-WECC format allows costs, environmental consequences, and capacity margin of the alternative cases, both within California and the Rest-of-WECC, to be most accurately understood. The subsections of this section discuss these results from a series of different perspectives, including: projected energy generation by type, projected California carbon responsibility, projected natural gas and coal used in power generation, projected generation costs, and projected emissions of criteria pollutants.

6.2.1 Energy Generation

This section compares the mix of energy generated across the various scenarios. The resource plan in dependable capacity terms will indicate what resources are available to meet load. Remote generators that are located outside of California, but whose energy is exported to meet California load, are included in the accounting for California based on the percentage owned by or under long-term contract to California LSEs. The following table indicates the portion of the remote generators' energy and costs that are allocated to California. The remaining portion of the remote generators is included in the Rest-of-WECC accounting.

Energy efficiency and PV solar were modeled as a resource, though they also could have been modeled as a load modifier, and they are included in the generation mix to facilitate comparisons across the cases. Energy generation for California and the Rest-of-WECC is shown graphically in the Figures 6-1 and 6-2 and numerically in Tables 6-10 and 6-11 for 2010, and then in the same format for 2020 using Figures 6-3 and 6-4 and Tables 6-12 and 6-13.

In 2010, natural gas is the predominate generation used to meet California load accounting for over 30 percent of California generation, followed by nuclear at about 13 percent, hydro at about 11 percent, and coal at about 9 percent. California relies on net imports to meet load, which account for almost 18 percent of its generation needs. Renewables, including large and small hydro, account for about 20 percent of the generation in California, and energy efficiency accounts for a small percentage of the generation at about 2 percent in all of the cases except Case 1.

In 2010, the Rest-of-WECC generation is predominately coal and hydro with coal accounting for about 31 percent of generation and hydro at about 28 percent, followed by natural gas at about 14 to 17 percent, depending on the case. Renewables, including small and large hydro, accounts for about 33 percent of the generation in the Rest-of-WECC.

By 2020, as preferred resources (i.e., renewables and energy efficiency) are added into the system, the preferred resources displace mostly natural gas-fired generation and imports generated by power plants in Rest-of-WECC (almost entirely natural gas). Coal generation remains fairly consistent across the cases except it declines in Case 5B with high levels of energy efficiency and renewables WECC-wide.

Figure 6-1: Composition of Generation to Meet California Load in 2010

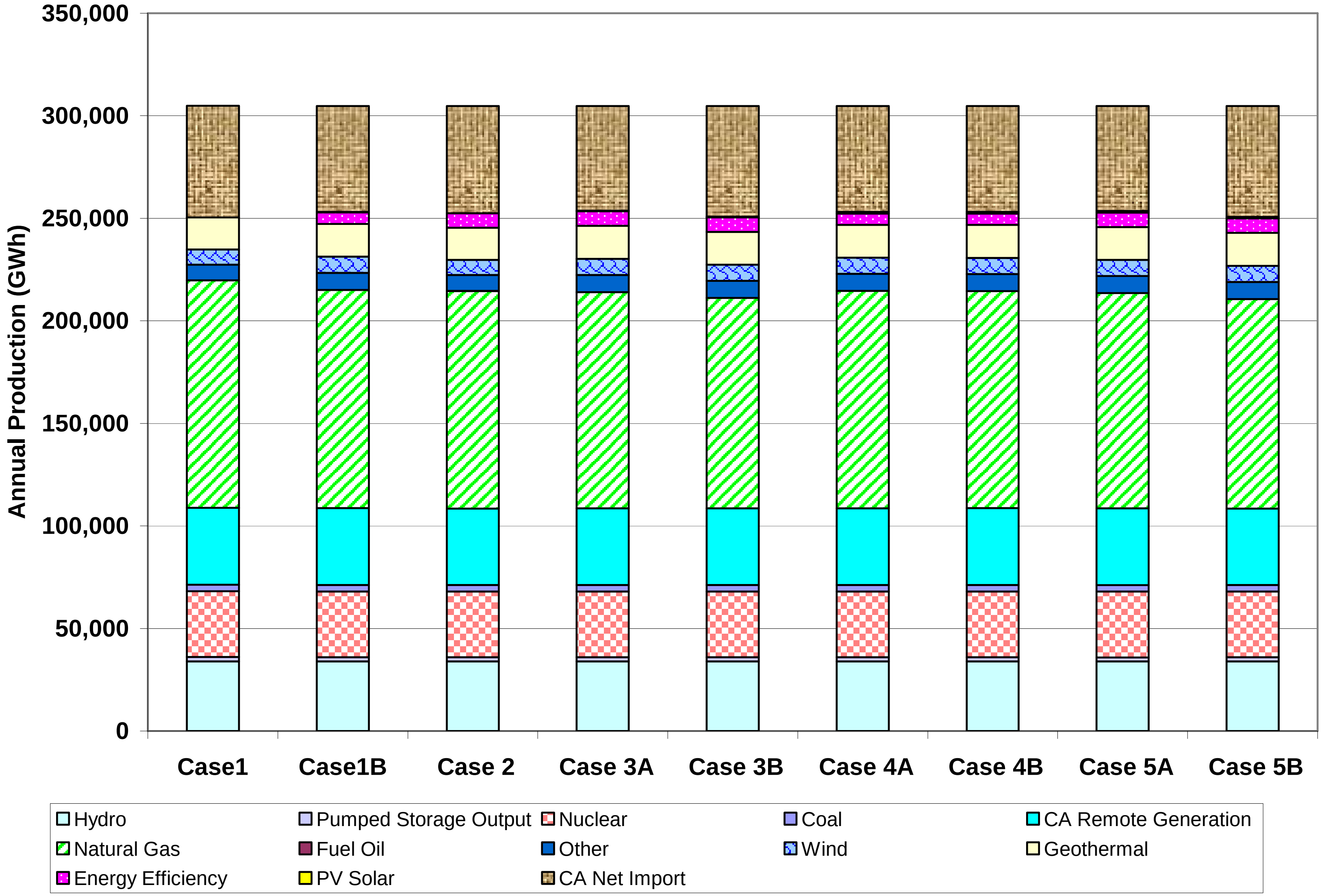


Table 6-10: Composition of Generation to Meet California Load in 2010

Fuel/Technology	Case 1	Case 1b	Case 2	Case 3a	Case 3b	Case 4a	Case 4b	Case 5a	Case 5b
Coal	3,158	3,157	3,157	3,157	3,157	3,157	3,157	3,157	3,157
Energy Efficiency	0	5,544	7,086	7,086	7,086	5,544	5,544	7,086	7,086
Fuel Oil	3	3	61	17	17	3	20	3	4
Geothermal	15,629	16,023	15,638	16,023	16,023	16,023	16,023	16,023	16,023
Hydro	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910
Natural Gas	111,008	106,397	106,046	105,406	102,591	105,909	105,846	104,893	102,136
Net Import	54,419	51,608	52,335	51,064	53,976	51,639	51,686	51,100	54,005
Nuclear	32,091	32,091	32,091	32,091	32,091	32,091	32,091	32,091	32,091
Other	7,630	8,336	7,713	8,333	8,313	8,341	8,342	8,341	8,320
Pumped Storage Output	2,129	2,046	2,038	2,032	2,037	2,026	2,034	1,993	2,009
PV Solar	0	329	0	329	329	784	784	784	784
Remote Generation	37,526	37,475	37,306	37,453	37,375	37,464	37,466	37,466	37,337
Wind	7,416	7,888	7,416	7,888	7,888	7,888	7,888	7,888	7,888

Figure 6-2: Composition of the Rest-of-WECC Generation in 2010

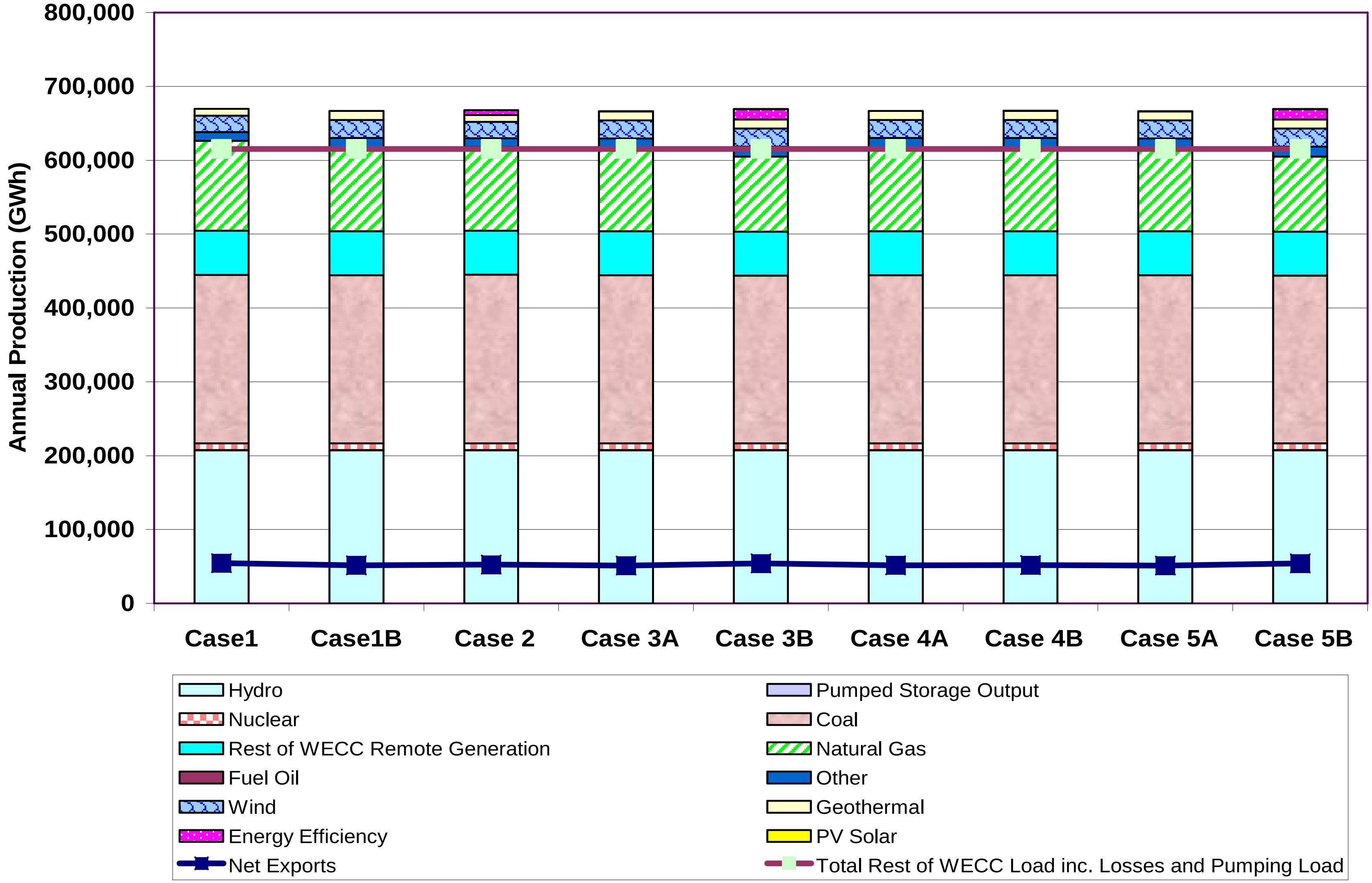


Table 6-11: Composition of Rest-of-WECC Generation in 2010

Fuel/Technology	Case 1	Case 1b	Case 2	Case 3a	Case 3b	Case 4a	Case 4b	Case 5a	Case 5b
Coal	228,066	227,675	228,455	227,642	227,132	227,641	227,615	227,672	227,057
Energy Efficiency	0	0	6,250	0	13,739	0	0	0	13,739
Fuel Oil	54	57	154	55	52	51	54	52	47
Geothermal	9,336	12,262	9,336	12,262	12,262	12,262	12,264	12,262	12,264
Hydro	207,122	207,122	207,122	207,122	207,122	207,122	207,122	207,122	207,122
Natural Gas	121,771	112,106	113,133	111,600	101,561	112,190	112,252	111,610	101,727
Nuclear	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251
Other	11,740	13,787	11,835	13,787	13,656	13,786	13,787	13,786	13,652
Pumped Storage Output	349	352	346	351	345	350	353	350	347
PV Solar	0	177	0	177	177	177	189	177	189
Rest-of-WECC Remote Generation	59,720	59,632	59,437	59,628	59,483	59,620	59,613	59,628	59,416
Wind	22,278	24,457	22,278	24,457	24,457	24,457	24,457	24,457	24,457

Figure 6-3: Composition of Generation to Meet California Load in 2020

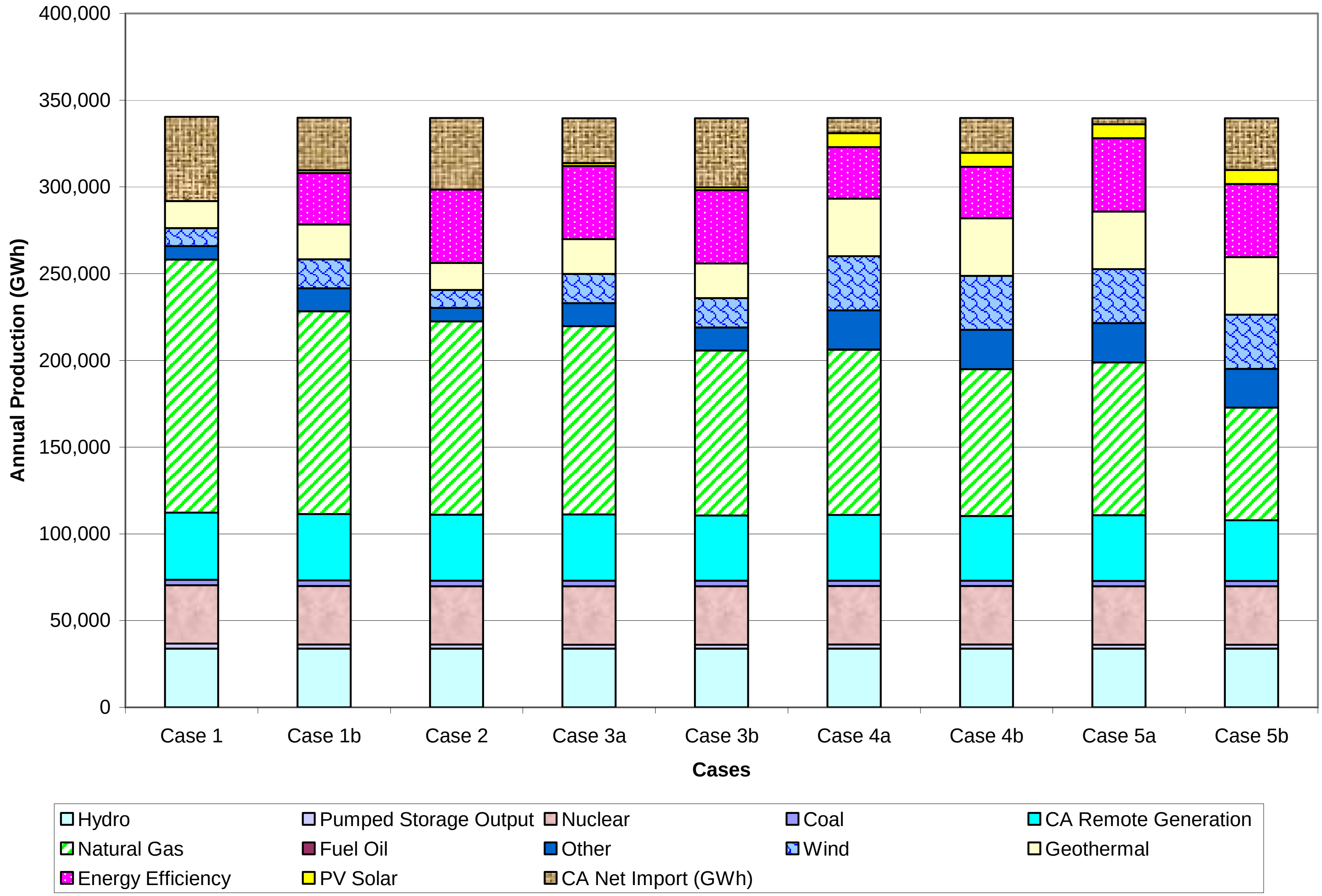


Table 6-12: Composition of Generation to Meet California Load in 2020

Fuel/Technology	Case 1	Case 1b	Case 2	Case 3a	Case 3b	Case 4a	Case 4b	Case 5a	Case 5b
Coal	3,158	3,158	3,158	3,158	3,158	3,157	3,155	3,157	3,120
Energy Efficiency	0	29,638	42,263	42,263	42,263	29,638	29,638	42,263	42,263
Fuel Oil	11	31	64	4	22	26	42	6	40
Geothermal	15,632	20,022	15,640	20,022	20,022	33,178	33,178	33,178	33,178
Hydro	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910
Natural Gas	145,878	116,771	111,370	108,511	95,115	95,282	84,663	88,108	64,976
Net Import	48,566	30,197	41,186	25,877	39,835	8,784	20,099	3,414	29,762
Nuclear	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,688
Other	7,729	13,290	7,755	13,285	13,243	22,668	22,590	22,650	22,217
Pumped Storage Output	2,805	2,370	2,271	2,204	2,215	2,302	2,297	2,165	2,158
PV Solar	0	1,629	0	1,629	1,629	8,036	8,036	8,036	8,036
Remote Generation	38,717	38,307	38,017	38,228	37,688	37,855	37,222	37,757	34,968
Wind	10,360	16,813	10,360	16,813	16,813	31,220	31,220	31,220	31,220

Figure 6-4: Composition of Generation to Meet Rest-of-WECC Load in 2020

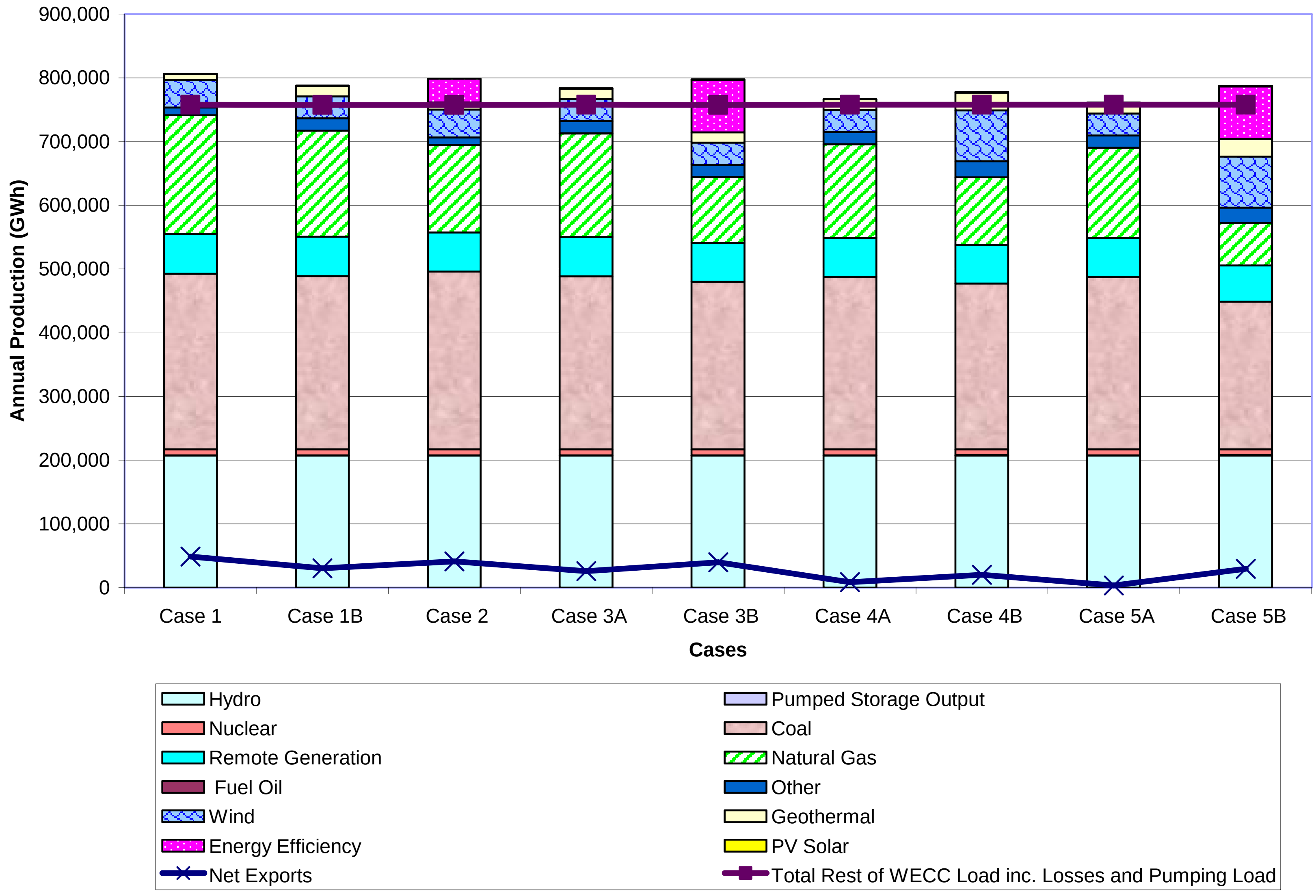


Table 6-13: Composition of Rest-of-WECC Generation in 2020

Fuel/Technology	Case 1	Case 1b	Case 2	Case 3a	Case 3b	Case 4a	Case 4b	Case 5a	Case 5b
Coal	275,537	271,629	278,967	271,510	263,129	270,692	260,102	270,370	231,618
Energy Efficiency	0	0	37,463	0	82,408	0	0	0	82,408
Fuel Oil	55	80	431	127	100	89	120	102	154
Geothermal	9,337	16,407	11,267	16,407	16,407	16,407	27,822	16,407	27,822
Hydro	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385
Natural Gas	186,469	166,441	136,958	162,303	103,463	146,781	106,498	141,907	66,362
Nuclear	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,246
Other	11,863	19,315	11,730	19,309	19,127	19,275	25,084	19,261	24,113
Pumped Storage Output	459	448	432	452	398	452	546	452	502
PV Solar	0	527	0	527	527	527	1,317	527	1,317
Rest-of-WECC Remote Generation	62,433	61,849	61,486	61,747	60,705	61,066	60,193	60,893	56,990
Wind	43,538	34,609	43,538	34,609	34,609	34,609	79,670	34,609	79,670

6.2.2 GHG Releases

Each generating unit modeled in the database is assigned an emission rate for CO2, and the simulation results record CO2 amounts based on the fuel burn of each unit. The total carbon emissions across the cases change as the energy generation changes across the cases. As noted in earlier chapters, the California responsibility for carbon consists of three categories: (1) power plants located in California, (2) power plants owned by or under long term contract to California LSEs, and (3) emissions from power plants located outside of California that correspond to "imports." Similarly, the Rest-of-WECC carbon emissions consist of the plants located in Rest-of-WECC serving Rest-of-WECC loads as well as the share of the remote plants serving Rest-of-WECC loads. The net imports into California are allocated CO2 based on the average carbon profile of the annual average generation mix for the Northwest and for the Southwest. Table 6-14 shows the carbon emissions for California and for the Rest-of-WECC and Figures 6-8 through 6-16 display carbon emissions in various graphical formats.

The change over time of California instate carbon production is largely based on the change in natural gas-fired generation. In Case 1, Current Conditions, natural gas-fired generation is added to meet future load growth while renewables and energy efficiency are added in small nominal amounts. As a result, the carbon production for Case 1 increases at a higher rate than any of the other cases with more preferred resources added. At the other spectrum, Case 5B is comprised of a high level of energy efficiency and renewables for both California and Rest-of-WECC. In this Case, California instate carbon emissions are the lowest, and noticeably lower than in Case 5A (high EE and High renewables in California only.)

Table 6-14 shows California's carbon by source. Figures 6-8 through 6-16 display this information graphically. Each of the figures for a case with more preferred resources than Case 1 has lower emissions than in Case 1. Total Case 1 emissions from all sources are shown on each of the subsequent figures to illustrate how this case compares to carbon emissions under Case 1. As a general rule, carbon emissions from "imports" change more than that from generators located directly in California or generators located outside of California, but owned or under long term contract to California LSEs.

Table 6-14: Carbon Emissions Through Time by Case

Carbon (000 tons)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Case 1												
California Responsibility	116,590	118,705	118,299	122,229	121,740	122,459	123,514	125,842	124,338	128,233	128,792	130,281
Rest of WECC	305,198	312,681	325,388	331,009	337,134	341,793	350,182	356,004	363,317	372,296	380,838	389,585
Total	421,788	431,386	443,687	453,238	458,874	464,253	473,696	481,845	487,655	500,529	509,630	519,866
Case 1B												
California Responsibility	114,688	115,359	113,071	113,280	108,725	107,244	107,124	108,152	105,483	108,273	107,607	107,976
Rest of WECC	303,082	310,803	322,216	328,253	334,836	340,260	348,672	354,413	362,529	372,410	381,659	391,051
Total	417,770	426,162	435,287	441,533	443,561	447,503	455,796	462,566	468,012	480,683	489,266	499,027
Case 2												
California Responsibility	114,825	115,443	113,458	115,686	113,568	112,550	111,822	112,524	109,457	111,879	110,700	110,588
Rest of WECC	303,991	310,590	322,801	327,095	331,540	334,787	341,870	346,852	354,449	362,203	368,476	375,521
Total	418,816	426,033	436,259	442,781	445,108	447,337	453,693	459,376	463,906	474,083	479,176	486,110
Case 3A												
California Responsibility	114,353	114,575	111,778	111,436	106,444	104,621	103,849	104,331	101,075	103,266	101,927	101,652
Rest of WECC	303,175	310,886	322,284	328,488	334,970	340,472	349,014	354,836	362,931	372,848	382,209	391,637
Total	417,528	425,461	434,062	439,924	441,414	445,092	452,864	459,167	464,006	476,113	484,137	493,289
Case 3B												
California Responsibility	114,653	115,234	112,561	112,349	107,660	106,044	105,463	106,014	102,984	105,521	104,230	104,294
Rest of WECC	299,940	304,297	311,501	314,126	317,338	319,620	324,767	327,247	331,990	338,712	343,362	349,461
Total	414,592	419,531	424,062	426,475	424,997	425,665	430,230	433,261	434,974	444,233	447,592	453,755
Case 4A												
California Responsibility	114,506	115,166	112,255	112,002	107,416	104,054	101,039	99,771	94,724	95,251	92,151	89,891
Rest of WECC	303,130	310,765	322,206	328,290	334,913	340,522	349,484	355,639	364,140	374,191	384,118	393,856
Total	417,636	425,931	434,460	440,292	442,330	444,576	450,523	455,410	458,864	469,443	476,269	483,747
Case 4B												
California Responsibility	114,519	115,179	112,158	111,925	107,396	104,157	101,249	100,042	95,301	95,899	92,870	90,938
Rest of WECC	303,140	310,819	321,349	324,528	328,940	331,452	337,614	340,660	345,392	352,204	356,539	362,102
Total	417,659	425,998	433,507	436,453	436,336	435,609	438,862	440,702	440,693	448,103	449,409	453,040
Case 5A												
California Responsibility	114,178	114,394	110,983	110,211	105,104	101,319	97,676	95,840	90,243	90,129	86,373	83,547
Rest of WECC	303,115	310,826	322,377	328,461	335,143	340,757	349,847	355,969	364,471	374,712	384,732	394,447
Total	417,293	425,219	433,360	438,671	440,247	442,076	447,523	451,808	454,714	464,840	471,105	477,994
Case 5B												
California Responsibility	114,447	115,020	111,739	111,147	106,535	103,058	99,506	97,625	92,265	92,058	88,377	85,545
Rest of WECC	299,944	304,224	311,547	311,142	312,000	311,108	311,960	311,032	310,827	310,705	311,151	309,604
Total	414,391	419,244	423,287	422,289	418,535	414,166	411,466	408,657	403,092	402,763	399,528	395,149

Note: California's carbon responsibility is the sum of instate production, remote generation, and net imports.

Figure 6-5: California Instate Carbon Production Through Time by Case

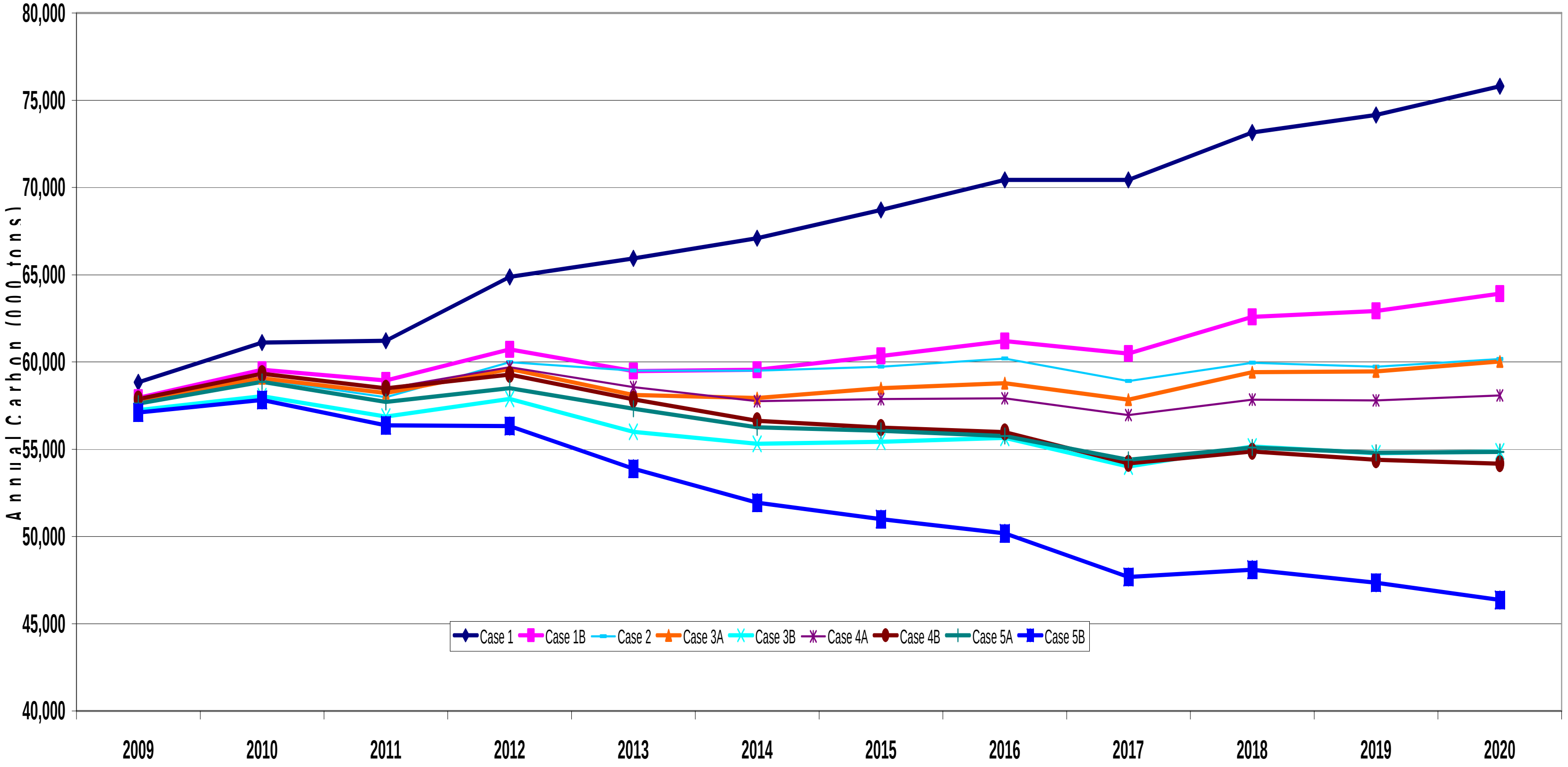


Figure 6-6: California Carbon Responsibility (Includes Instate Generation, Remote Generation and Net Imports Through Time by Case)

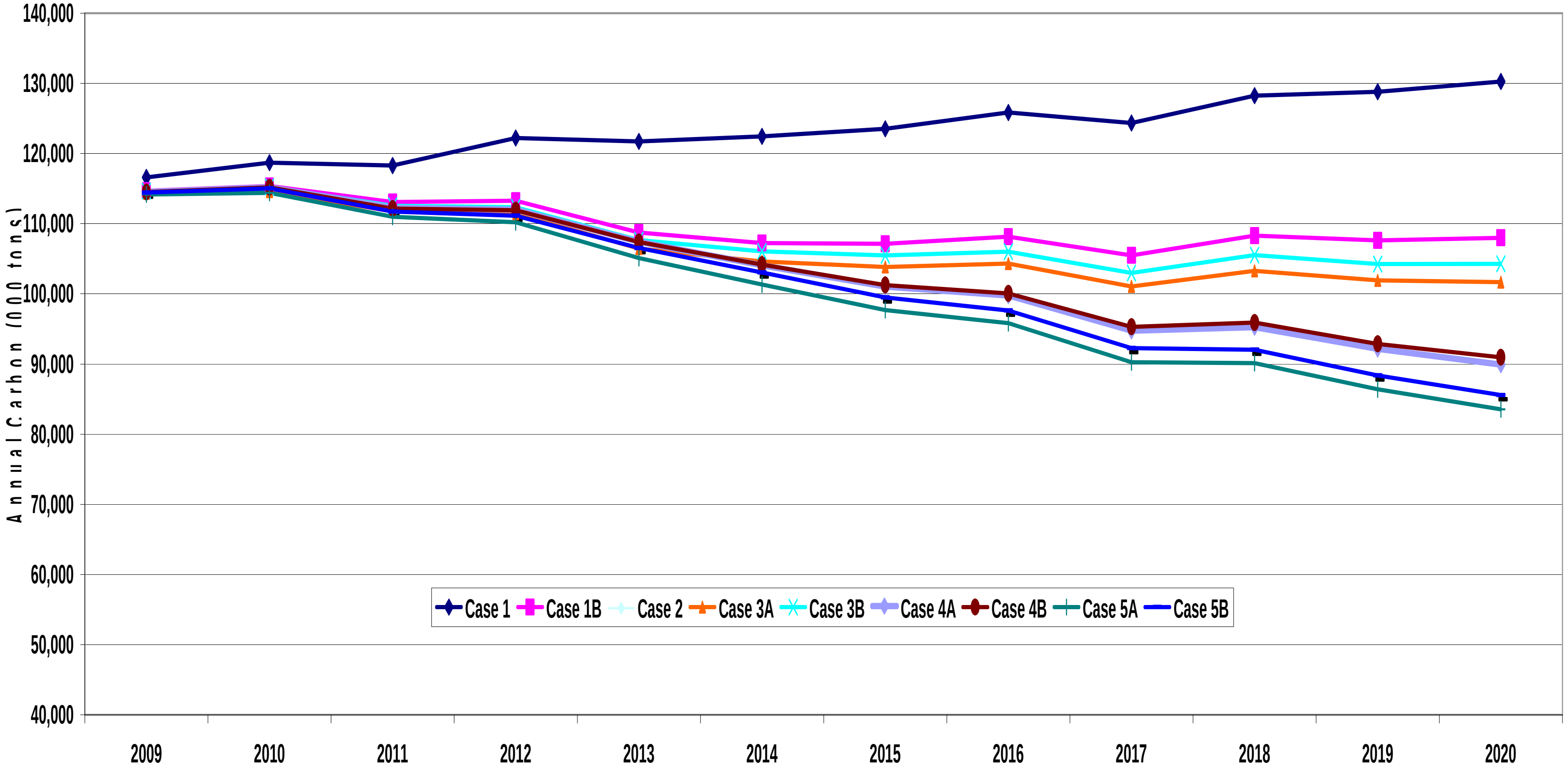


Figure 6-7: Rest-of-WECC Carbon Production Through Time by Case

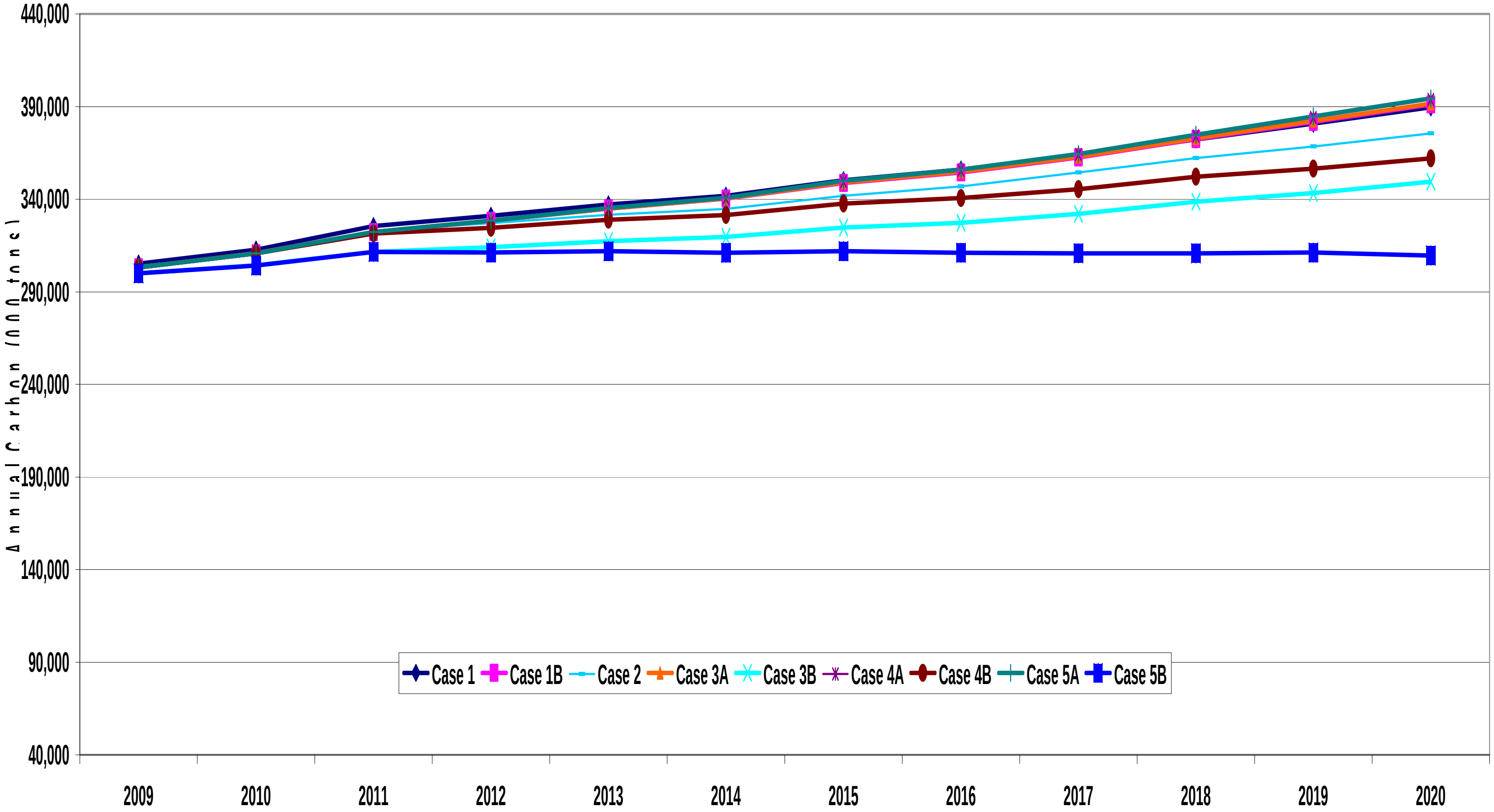


Table 6-15: California Carbon Responsibility by Source by Case

Carbon (000 tons)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Case 1												
Instate Generation	58,827	61,112	61,214	64,865	65,930	67,096	68,713	70,435	70,440	73,142	74,149	75,803
Remote Generation	27,145	26,964	26,925	27,065	27,058	27,098	27,168	27,218	27,221	27,232	27,240	27,267
Net Imports	30,618	30,629	30,160	30,299	28,752	28,266	27,633	28,188	26,677	27,859	27,402	27,211
Total	116,590	118,705	118,299	122,229	121,740	122,459	123,514	125,842	124,338	128,233	128,792	130,281
Case 1B												
Instate Generation	57,940	59,543	58,940	60,714	59,471	59,546	60,344	61,203	60,481	62,575	62,922	63,907
Remote Generation	27,103	26,939	26,851	26,942	26,913	26,938	27,009	27,083	27,080	27,099	27,098	27,087
Net Imports	29,645	28,877	27,280	25,624	22,341	20,760	19,772	19,866	17,921	18,600	17,587	16,982
Total	114,688	115,359	113,071	113,280	108,725	107,244	107,124	108,152	105,483	108,273	107,607	107,976
Case 2												
Instate Generation	57,680	59,003	57,977	59,987	59,504	59,508	59,733	60,201	58,910	59,957	59,729	60,164
Remote Generation	27,047	26,864	26,728	26,815	26,843	26,843	26,923	26,953	26,953	26,984	26,978	26,946
Net Imports	30,098	29,577	28,753	28,885	27,221	26,199	25,166	25,370	23,593	24,938	23,993	23,477
Total	114,825	115,443	113,458	115,686	113,568	112,550	111,822	112,524	109,457	111,879	110,700	110,588
Case 3A												
Instate Generation	57,803	59,066	58,209	59,589	58,113	57,927	58,495	58,781	57,842	59,408	59,462	60,032
Remote Generation	27,096	26,930	26,848	26,911	26,885	26,914	26,975	27,053	27,039	27,065	27,062	27,048
Net Imports	29,453	28,580	26,721	24,937	21,446	19,780	18,380	18,497	16,193	16,792	15,404	14,572
Total	114,353	114,575	111,778	111,436	106,444	104,621	103,849	104,331	101,075	103,266	101,927	101,652
Case 3B												
Instate Generation	57,240	58,031	56,860	57,892	55,999	55,304	55,430	55,658	54,002	55,162	54,764	54,868
Remote Generation	27,060	26,892	26,735	26,806	26,751	26,744	26,786	26,828	26,809	26,791	26,836	26,755
Net Imports	30,353	30,312	28,966	27,652	24,909	23,996	23,248	23,528	22,174	23,568	22,629	22,671
Total	114,653	115,234	112,561	112,349	107,660	106,044	105,463	106,014	102,984	105,521	104,230	104,294
Case 4A												
Instate Generation	57,866	59,340	58,469	59,695	58,555	57,758	57,878	57,913	56,958	57,839	57,796	58,078
Remote Generation	27,092	26,935	26,838	26,935	26,901	26,906	26,939	26,988	26,918	26,931	26,906	26,843
Net Imports	29,549	28,890	26,948	25,372	21,960	19,390	16,222	14,870	10,848	10,482	7,449	4,970
Total	114,506	115,166	112,255	112,002	107,416	104,054	101,039	99,771	94,724	95,251	92,151	89,891
Case 4B												
Instate Generation	57,868	59,323	58,490	59,279	57,850	56,623	56,240	55,978	54,179	54,876	54,391	54,172
Remote Generation	27,091	26,935	26,859	26,914	26,851	26,813	26,829	26,842	26,688	26,619	26,545	26,314
Net Imports	29,561	28,921	26,809	25,731	22,695	20,721	18,179	17,222	14,435	14,404	11,934	10,451
Total	114,519	115,179	112,158	111,925	107,396	104,157	101,249	100,042	95,301	95,899	92,870	90,938
Case 5A												
Instate Generation	57,619	58,862	57,707	58,507	57,318	56,251	56,052	55,750	54,396	55,092	54,801	54,836
Remote Generation	27,086	26,938	26,831	26,896	26,880	26,849	26,908	26,922	26,876	26,862	26,833	26,777
Net Imports	29,473	28,594	26,445	24,808	20,906	18,219	14,716	13,168	8,971	8,175	4,740	1,934
Total	114,178	114,394	110,983	110,211	105,104	101,319	97,676	95,840	90,243	90,129	86,373	83,547
Case 5B												
Instate Generation	57,110	57,829	56,378	56,321	53,889	51,927	50,993	50,181	47,680	48,096	47,348	46,356
Remote Generation	27,053	26,874	26,730	26,766	26,637	26,513	26,399	26,128	25,528	25,346	24,944	24,257
Net Imports	30,284	30,317	28,632	28,060	26,009	24,618	22,114	21,316	19,057	18,616	16,086	14,932
Total	114,447	115,020	111,739	111,147	106,535	103,058	99,506	97,625	92,265	92,058	88,377	85,545

Figure 6-8: California Carbon Responsibility for Case 1 (Current Conditions)

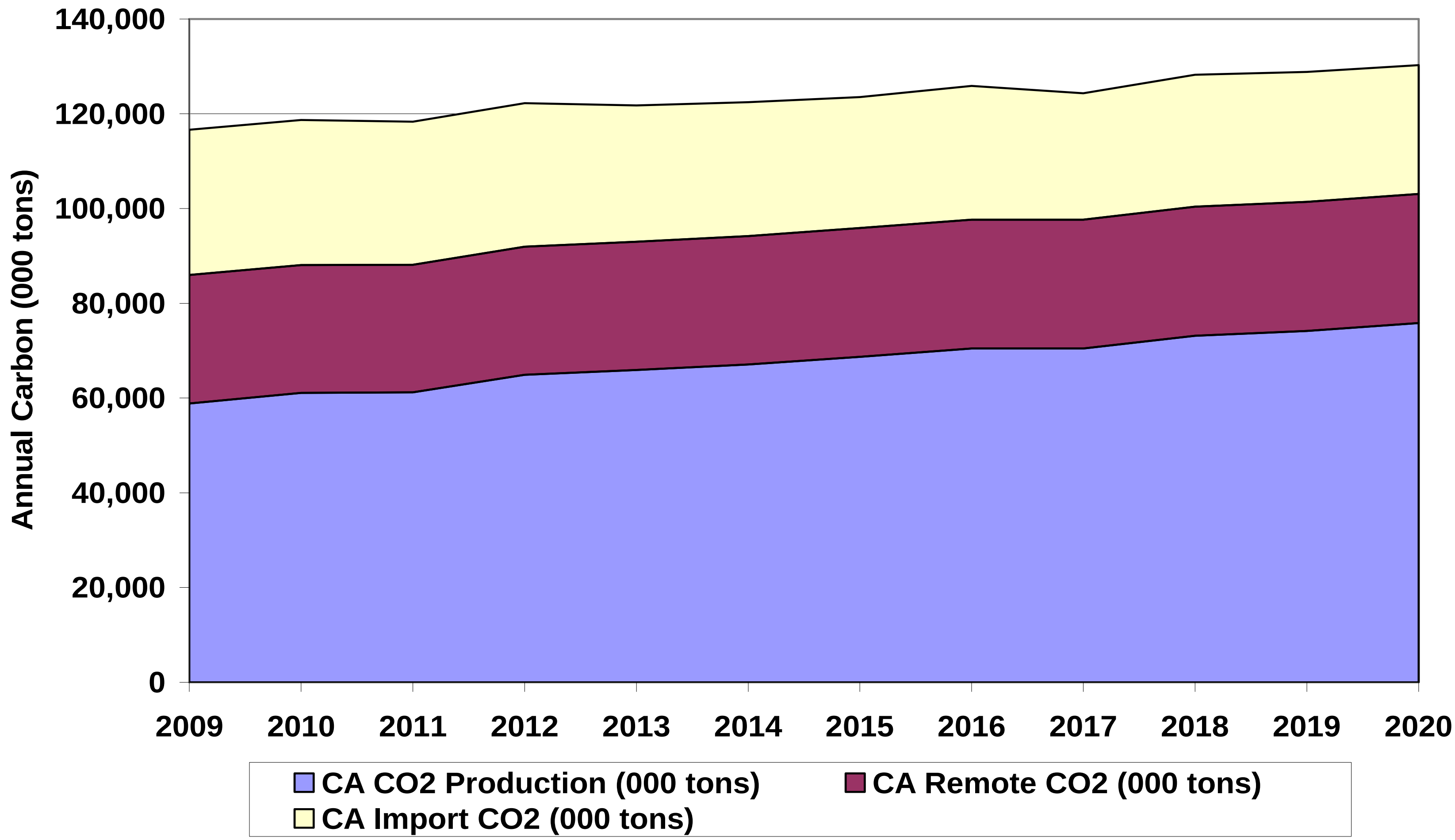


Figure 6-9: California Carbon Responsibility for Case 1B (Current Requirements)

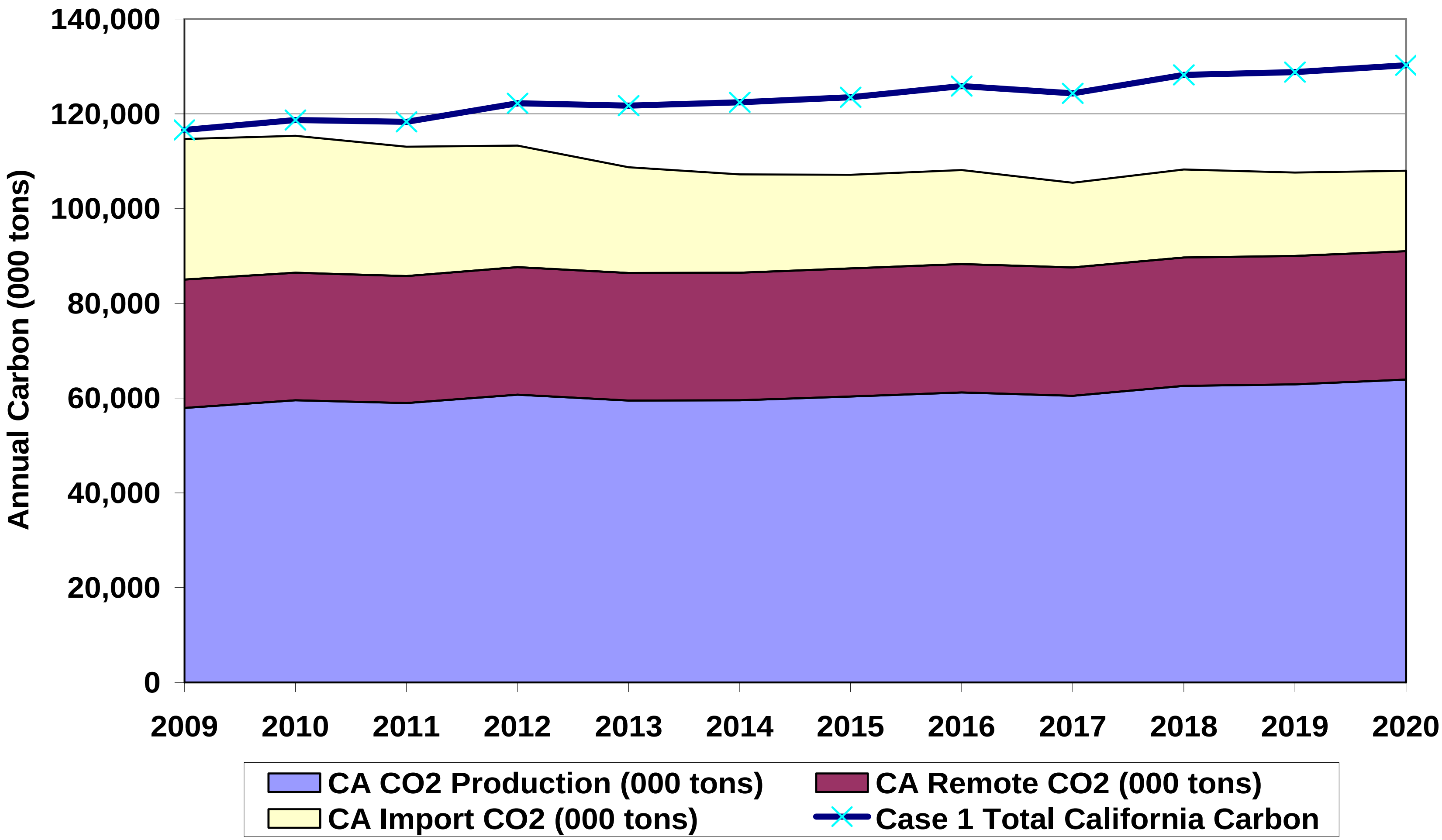


Figure 6-10: California Carbon Responsibility for Case 2 (Sustained High Gas Prices)

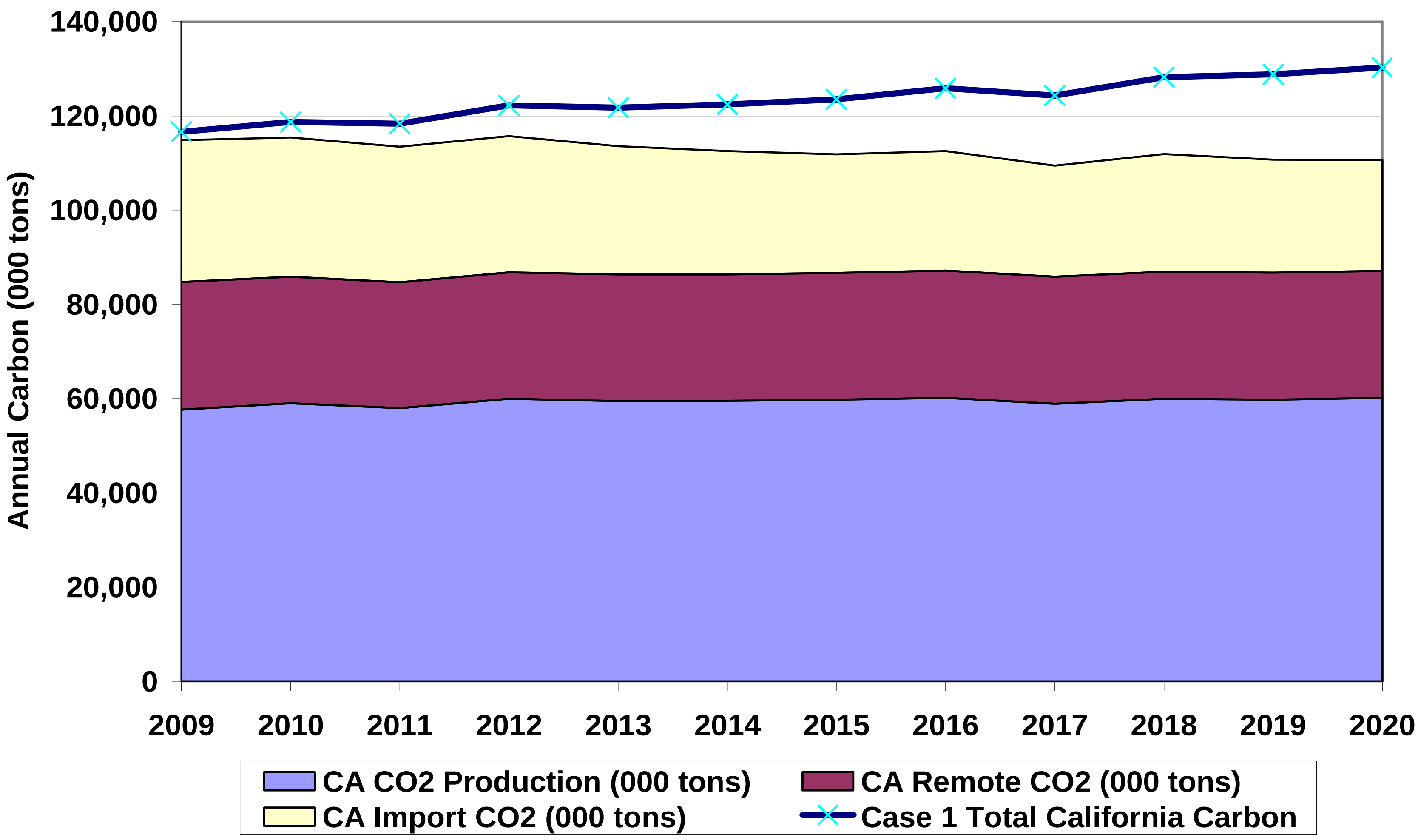


Figure 6-11: California Carbon Responsibility for Case 3A (High Energy Efficiency Instate)

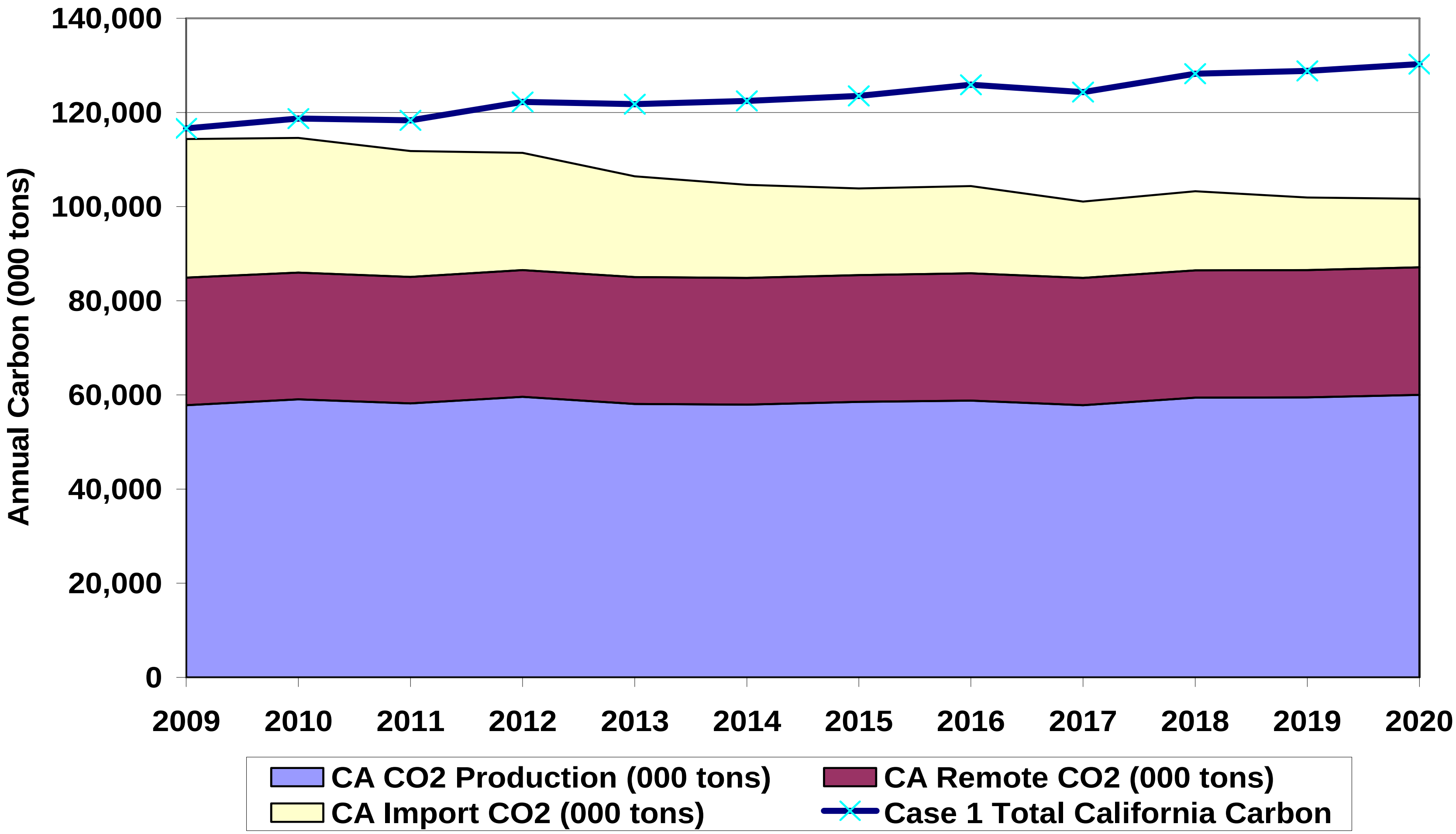


Figure 6-12: California Carbon Responsibility for Case 3B (High Energy Efficiency Instate and in Rest-of-WECC)

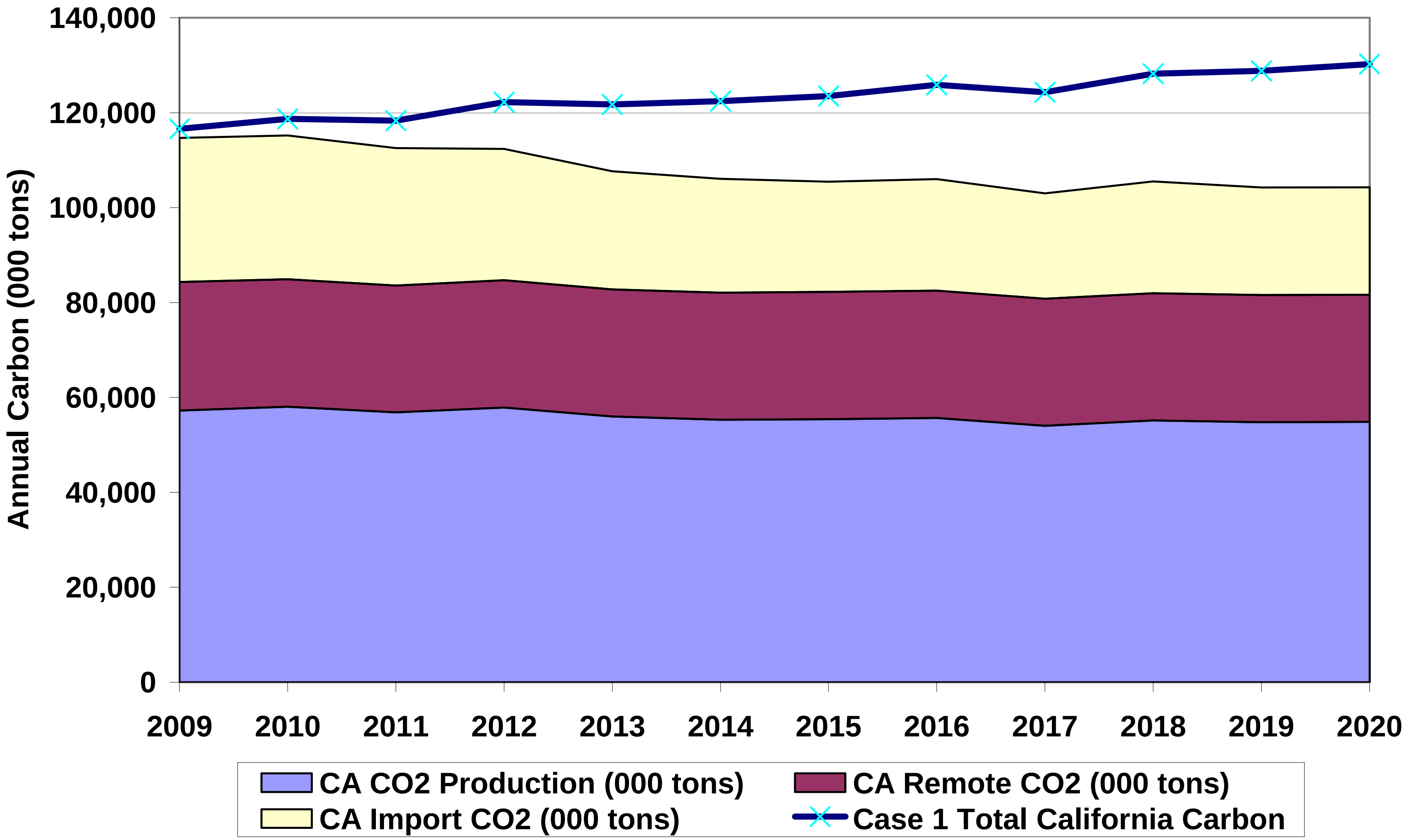


Figure 6-13: California Carbon Responsibility for Case 4A (High Renewables Instate)

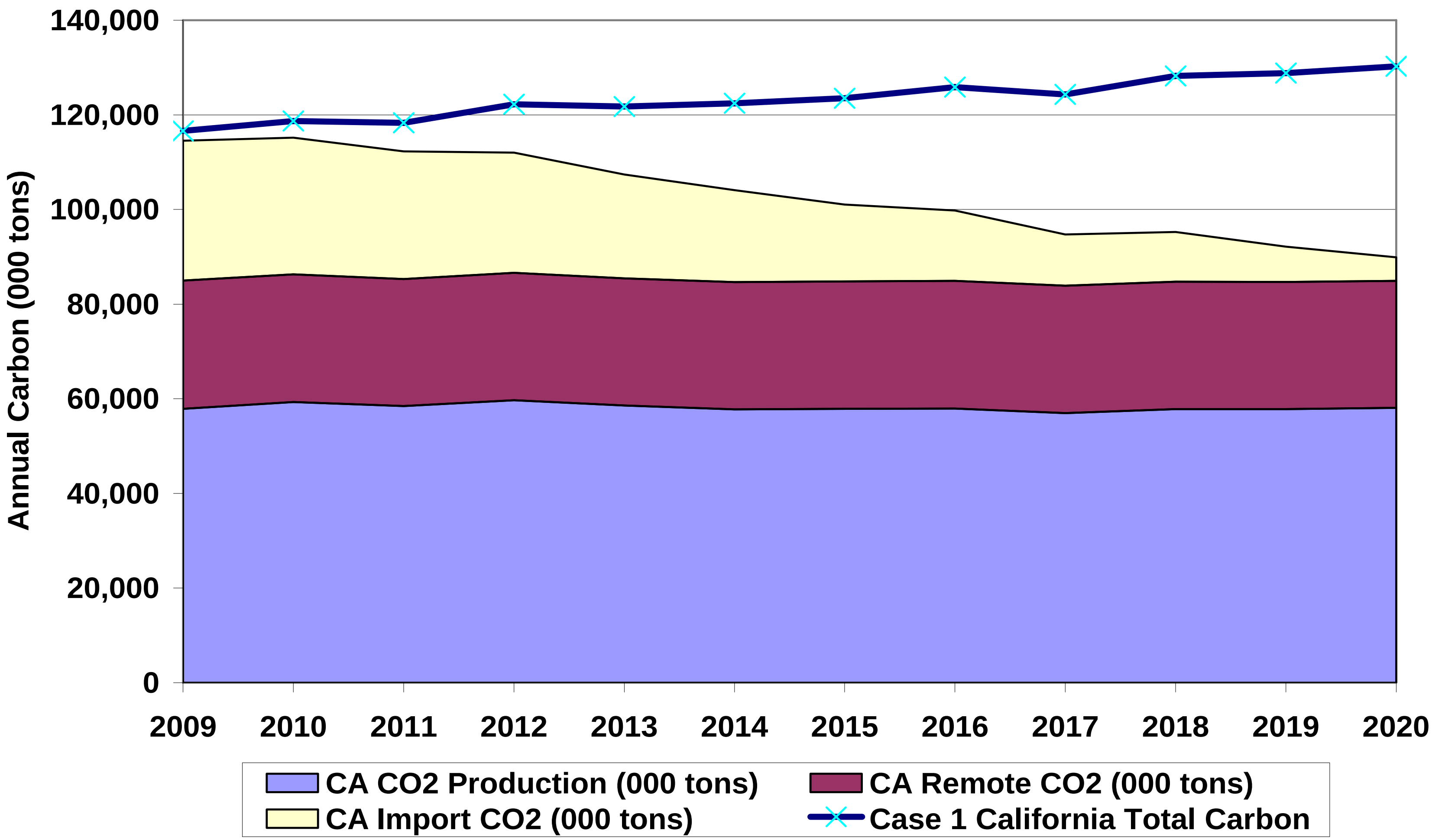


Figure 6-14: California Carbon Responsibility for Case 4B (High Renewables Instate and in Rest-of-WECC)

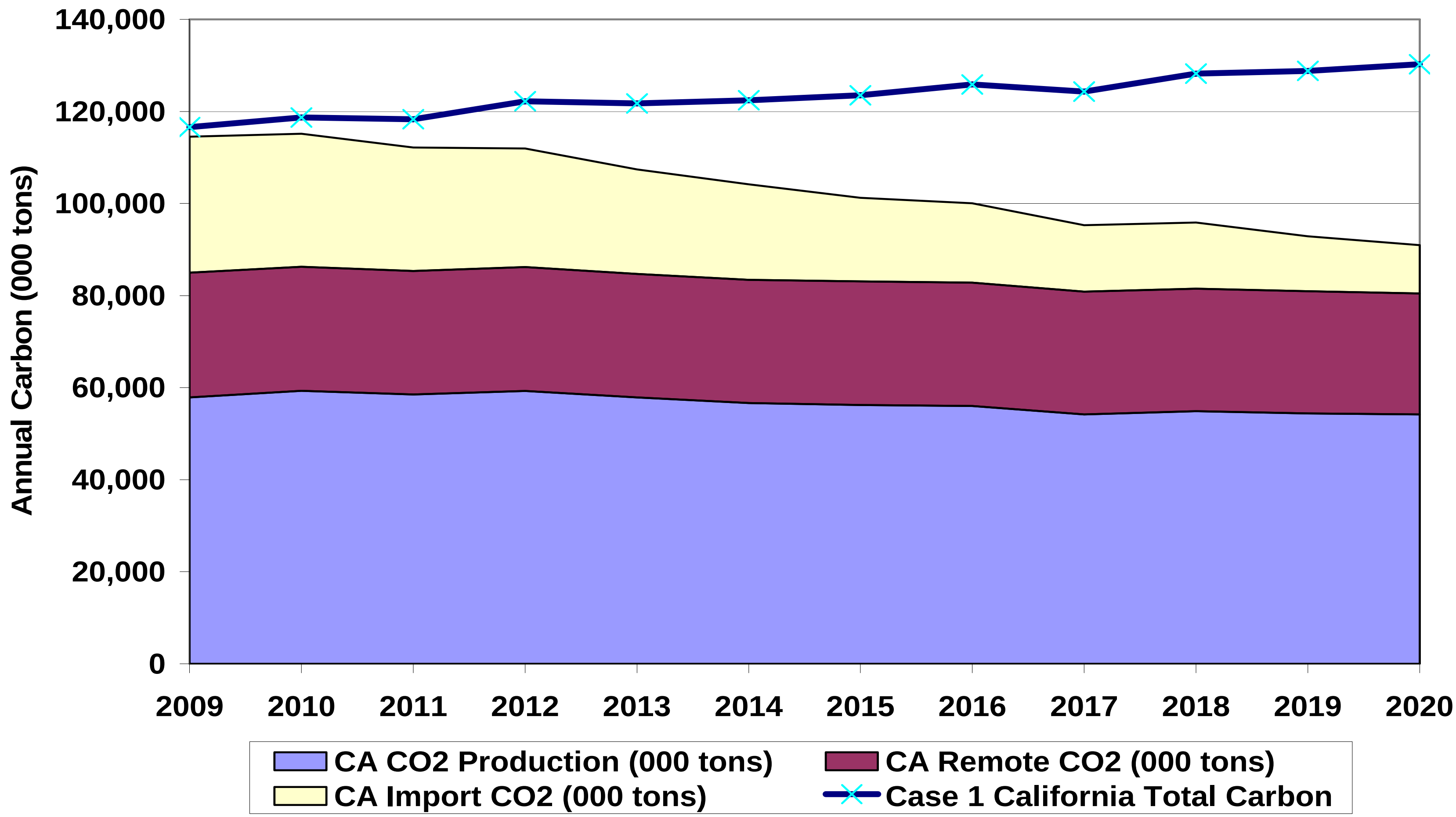


Figure 6-15: California Carbon Responsibility for Case 5A (High Energy Efficiency and Renewables Instate)

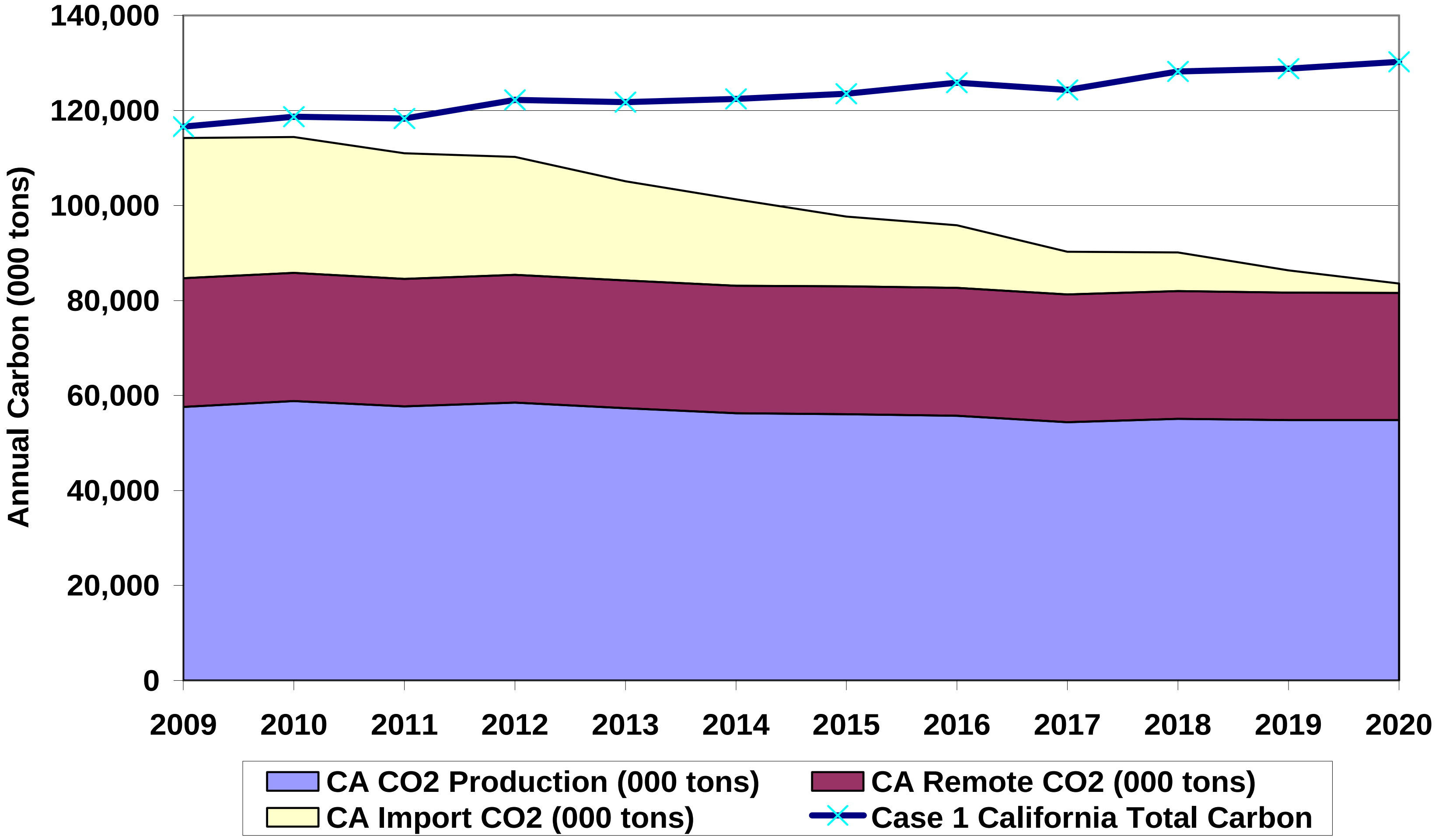
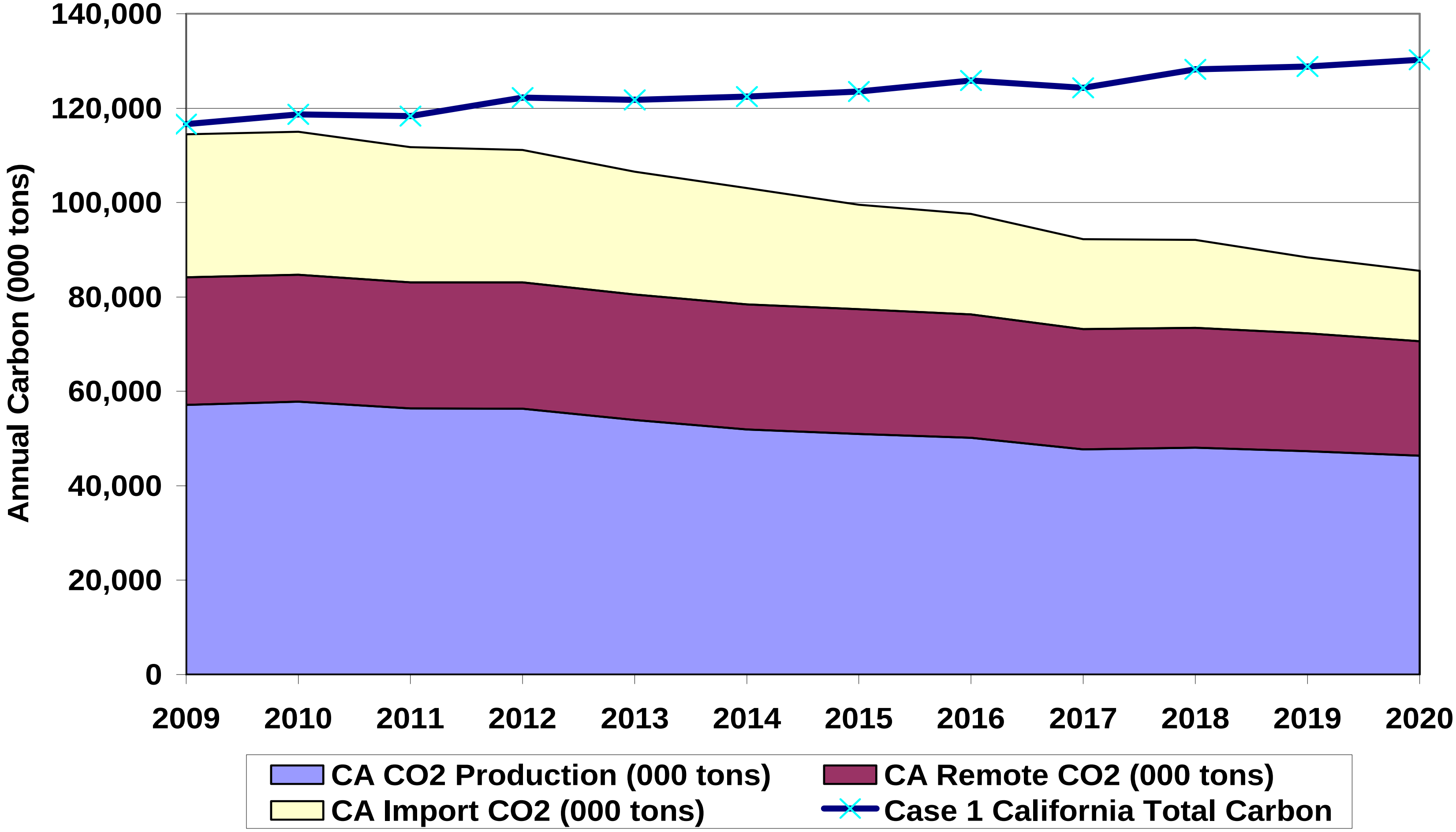


Figure 6-16: California Carbon Responsibility for Case 5B (High Energy Efficiency and Renewables Instate and in Rest-of-WECC)



6.2.3 Fuel Use

This subsection compares the fuel use by fuel type across the Cases with a separate set of charts for each of the two fuels. The energy generation shown in Section 6.2.1 reveals that natural gas generation in California and the Rest-of-WECC is the principal generating technology that is displaced as more preferred resources are added to the system. Much less change in coal consumption occurs.

Figures 6-17 through 6-19 and Table 6-16 show natural gas fuel consumption in several formats. California natural gas consumption for power generation declines in all cases, including the implications of existing and speculative preferred resources. Figure 6-19, by focusing attention just to results for year 2020, shows this clearly. Total WECC natural gas consumption in Figure 6-17 does not show declines compared to Case 1 except for Cases 3B and 5B, both of which include substantial energy efficiency impacts.

Figures 6-20 and 6-21 and Table 6-17 show coal as a power generation fuel in several formats. Total WECC coal consumption as a power generation fuel increases in all cases except the combined high efficiency and high renewables case. Even in this case, the 2020 consumption level is likely to be above recent historical data (not shown on the chart).

Figure 6-17: Total WECC Natural Gas Consumption (GBTu)

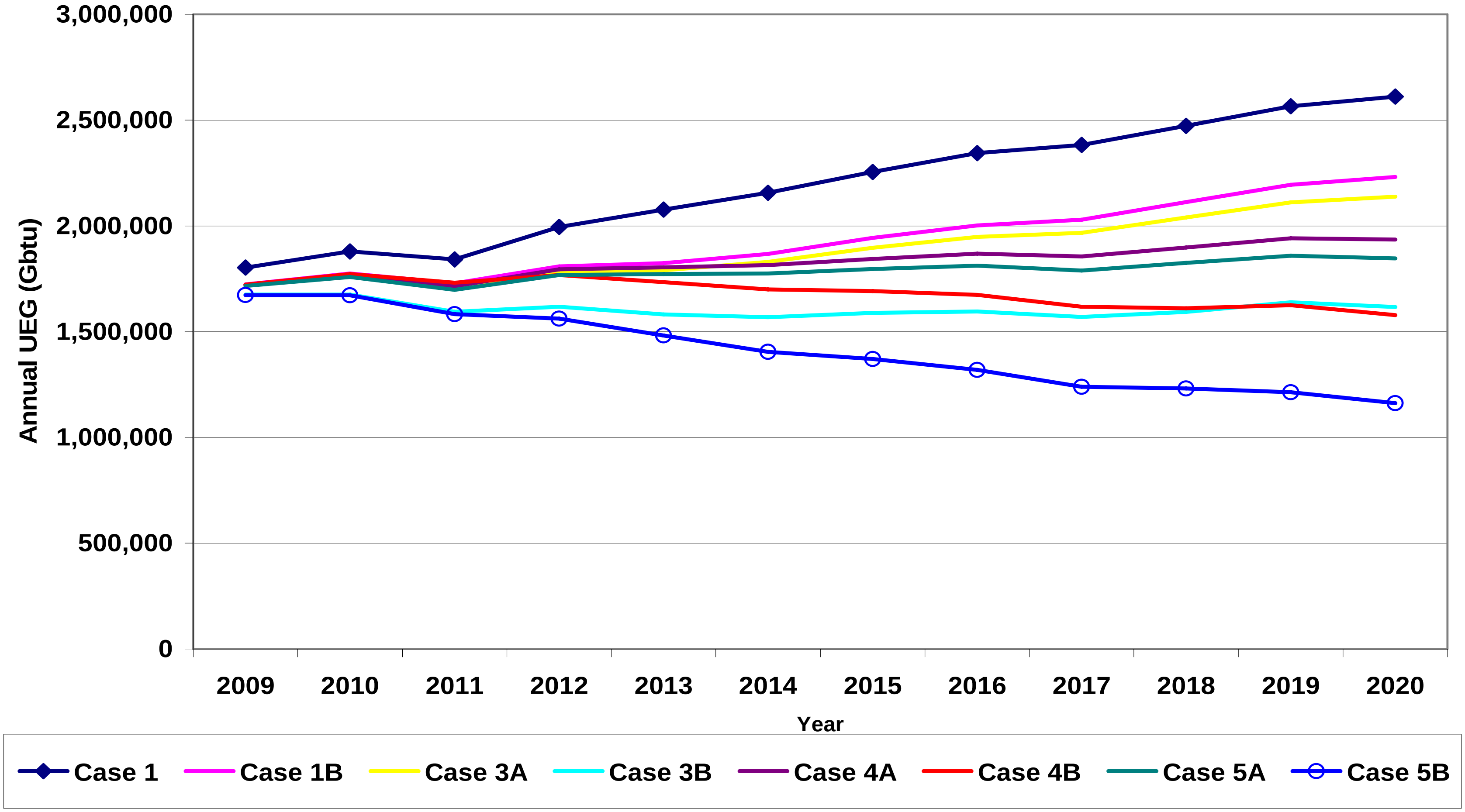


Figure 6-18: Total California Gas Consumption (GBTu)

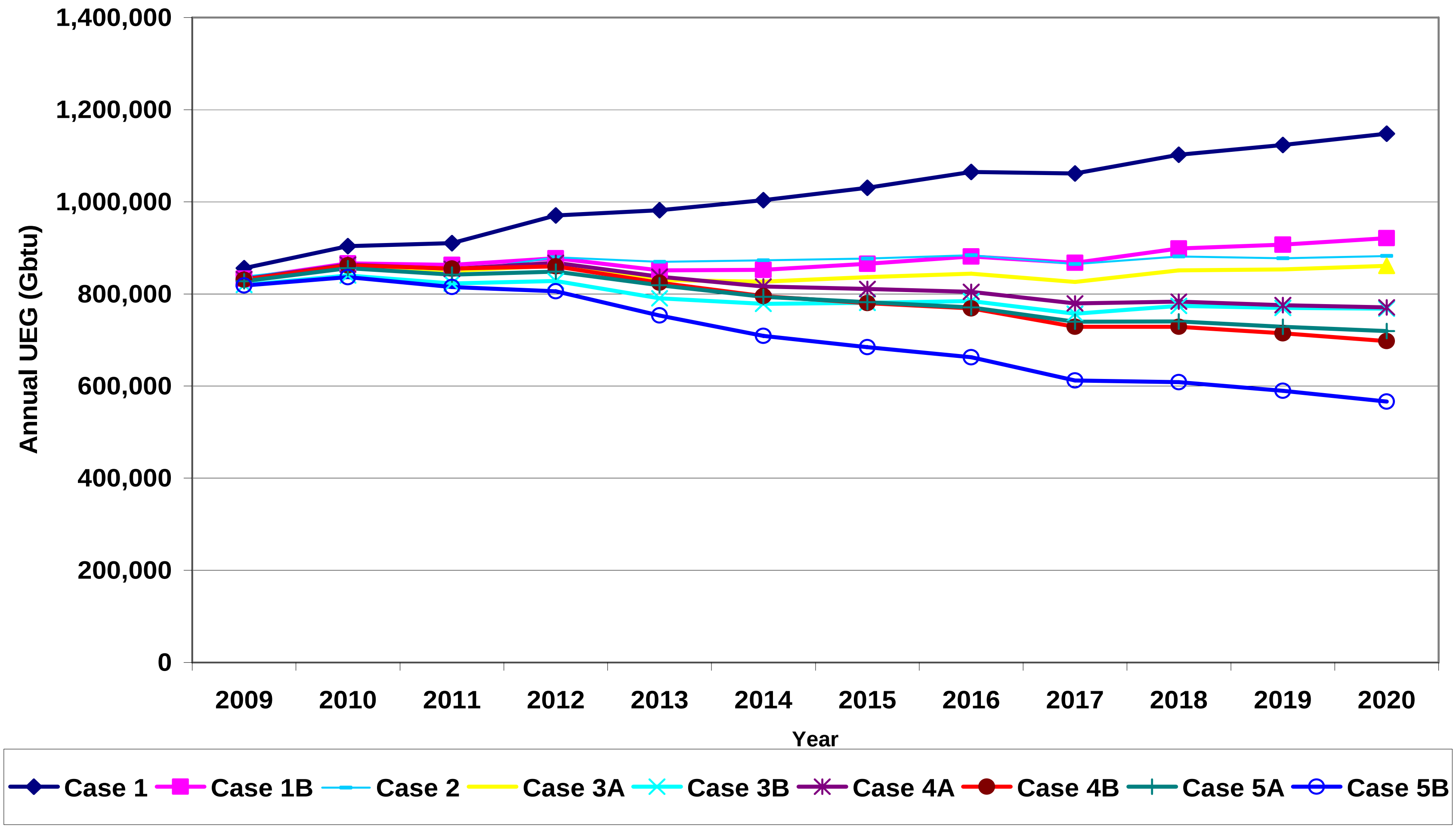


Figure 6-19: Comparison of UEG Gas Consumption Across Cases for 2020

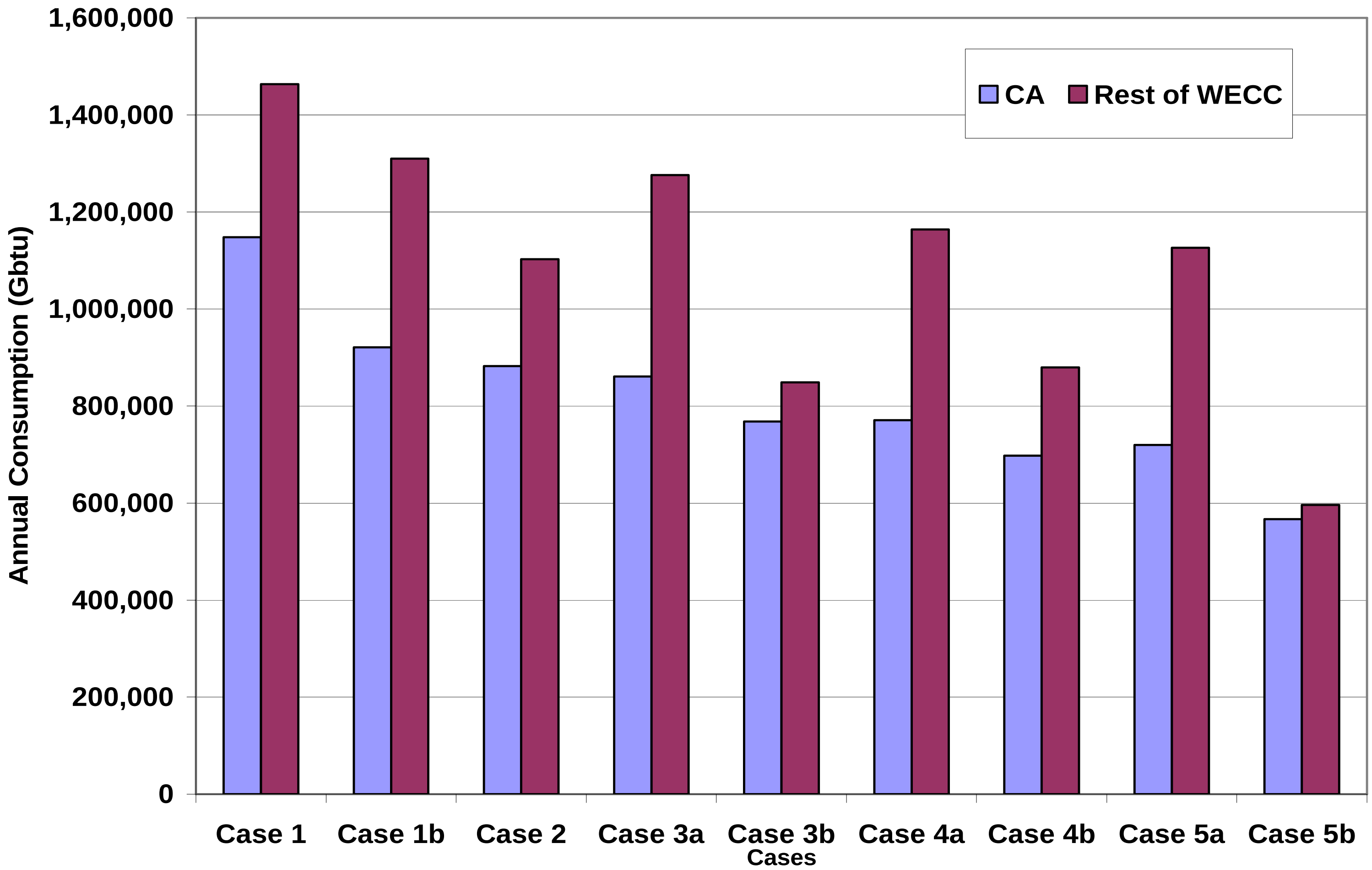


Table 6-16: Natural Gas Consumption Through Time for Each Thematic Case (GBTu)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Case 1												
CA Gas	855,827	903,651	910,254	970,110	981,891	1,003,597	1,030,290	1,064,677	1,061,703	1,102,061	1,123,244	1,147,817
Rest of WECC Gas	946,490	974,904	930,939	1,024,648	1,094,537	1,153,424	1,224,995	1,279,582	1,320,468	1,370,905	1,442,586	1,463,538
Total WECC Gas	1,802,317	1,878,556	1,841,194	1,994,758	2,076,428	2,157,021	2,255,284	2,344,259	2,382,171	2,472,966	2,565,830	2,611,355
Case 1B												
CA Gas	833,044	866,645	863,015	877,288	851,076	852,081	865,352	880,979	867,602	898,812	907,000	921,037
Rest of WECC Gas	890,671	907,854	866,278	931,958	972,661	1,015,640	1,077,894	1,120,762	1,161,850	1,213,316	1,286,866	1,309,985
Total WECC Gas	1,723,715	1,774,499	1,729,293	1,809,247	1,823,738	1,867,721	1,943,246	2,001,741	2,029,452	2,112,128	2,193,866	2,231,021
Case 2												
CA Gas	837,395	862,636	846,939	879,387	869,598	873,094	877,069	884,152	864,739	881,172	877,173	882,382
Rest of WECC Gas	914,782	914,504	842,732	909,424	955,180	987,735	1,026,938	1,058,711	1,042,646	1,069,984	1,105,563	1,102,342
Total WECC Gas	1,752,178	1,777,140	1,689,671	1,788,811	1,824,778	1,860,829	1,904,007	1,942,863	1,907,384	1,951,156	1,982,736	1,984,724
Case 3A												
CA Gas	830,426	858,509	850,235	861,750	830,470	826,341	836,637	843,815	826,046	851,328	853,312	861,060
Rest of WECC Gas	890,346	904,906	859,079	922,626	959,344	1,003,101	1,059,728	1,103,795	1,140,746	1,187,933	1,258,082	1,276,222
Total WECC Gas	1,720,772	1,763,415	1,709,314	1,784,376	1,789,815	1,829,441	1,896,365	1,947,611	1,966,792	2,039,261	2,111,395	2,137,282
Case 3B												
CA Gas	819,539	840,130	822,813	828,264	790,619	778,499	780,665	784,218	756,896	774,283	769,520	767,818
Rest of WECC Gas	855,711	834,559	771,083	789,329	790,331	789,752	807,482	810,914	812,406	818,627	869,554	848,449
Total WECC Gas	1,675,249	1,674,689	1,593,896	1,617,594	1,580,949	1,568,251	1,588,147	1,595,132	1,569,302	1,592,910	1,639,074	1,616,267
Case 4A												
CA Gas	831,883	863,545	854,351	867,493	837,425	816,122	810,850	804,562	779,295	783,272	775,710	770,884
Rest of WECC Gas	890,468	907,709	861,069	927,134	966,939	998,293	1,033,286	1,063,770	1,076,114	1,113,845	1,164,829	1,163,891
Total WECC Gas	1,722,351	1,771,254	1,715,419	1,794,627	1,804,364	1,814,415	1,844,136	1,868,332	1,855,409	1,897,117	1,940,539	1,934,775
Case 4B												
CA Gas	830,687	862,073	854,930	859,762	824,206	795,352	779,969	768,814	728,935	728,876	714,613	697,557
Rest of WECC Gas	891,632	910,389	876,861	907,852	909,308	904,308	910,981	904,643	888,826	881,615	909,719	879,790
Total WECC Gas	1,722,318	1,772,462	1,731,790	1,767,614	1,733,515	1,699,660	1,690,950	1,673,458	1,617,761	1,610,491	1,624,332	1,577,347
Case 5A												
CA Gas	827,882	856,182	842,073	848,522	818,811	793,640	782,072	770,596	739,867	740,049	728,596	719,623
Rest of WECC Gas	888,475	902,164	855,316	918,989	953,787	981,390	1,013,634	1,041,086	1,049,071	1,085,391	1,130,677	1,126,281
Total WECC Gas	1,716,357	1,758,346	1,697,389	1,767,511	1,772,598	1,775,030	1,795,706	1,811,682	1,788,937	1,825,440	1,859,273	1,845,905
Case 5B												
CA Gas	818,097	836,360	814,803	805,737	753,450	709,120	684,587	662,803	612,444	608,340	589,934	566,556
Rest of WECC Gas	854,293	834,839	767,715	756,213	728,271	695,006	686,374	656,142	626,381	623,225	623,654	595,856
Total WECC Gas	1,672,390	1,671,199	1,582,518	1,561,950	1,481,722	1,404,126	1,370,961	1,318,945	1,238,826	1,231,565	1,213,587	1,162,412

Figure 6-20: Total WECC Coal Consumption (GBTu)

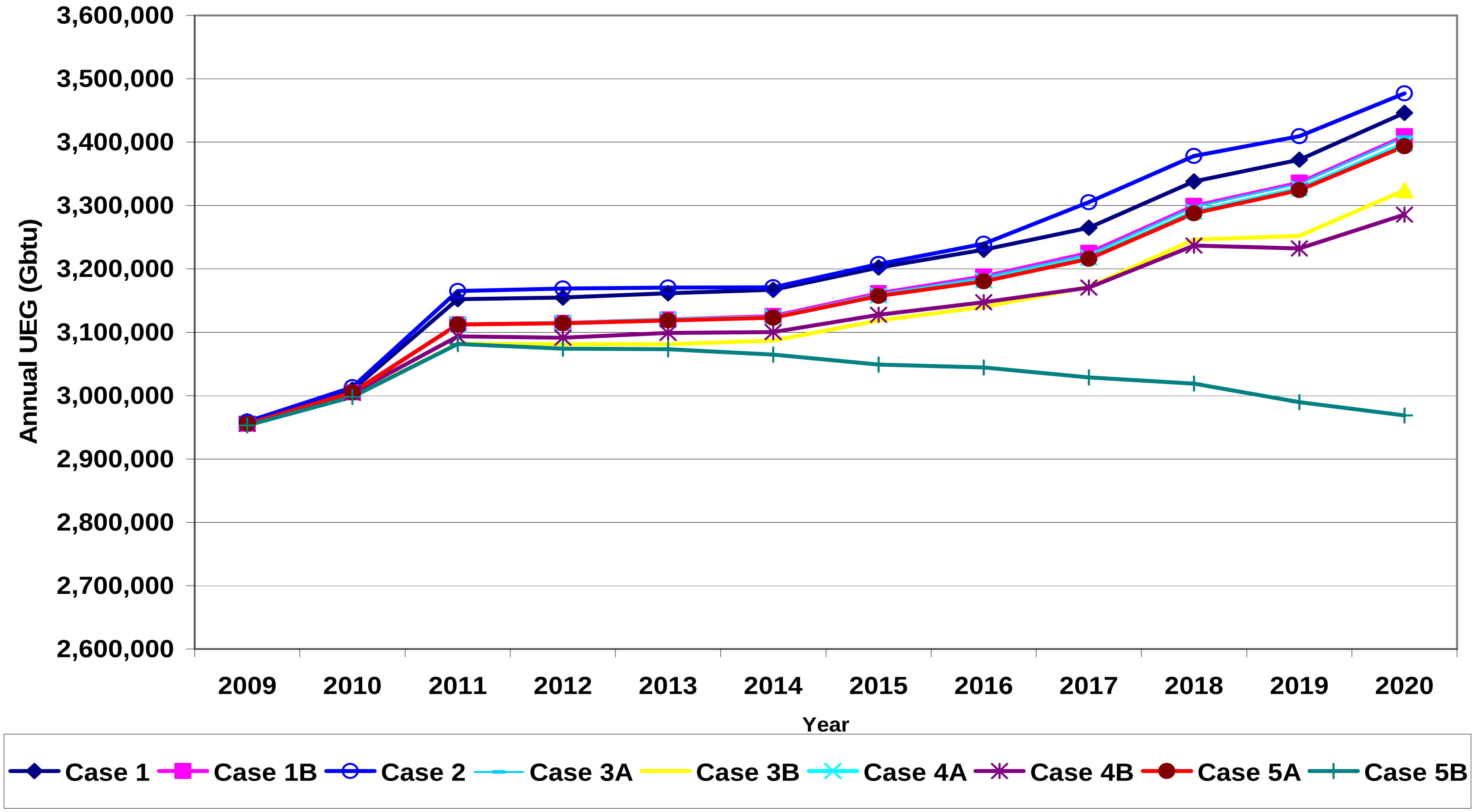


Figure 6-21: Comparison of UEG Coal Consumption Across Cases for 2020

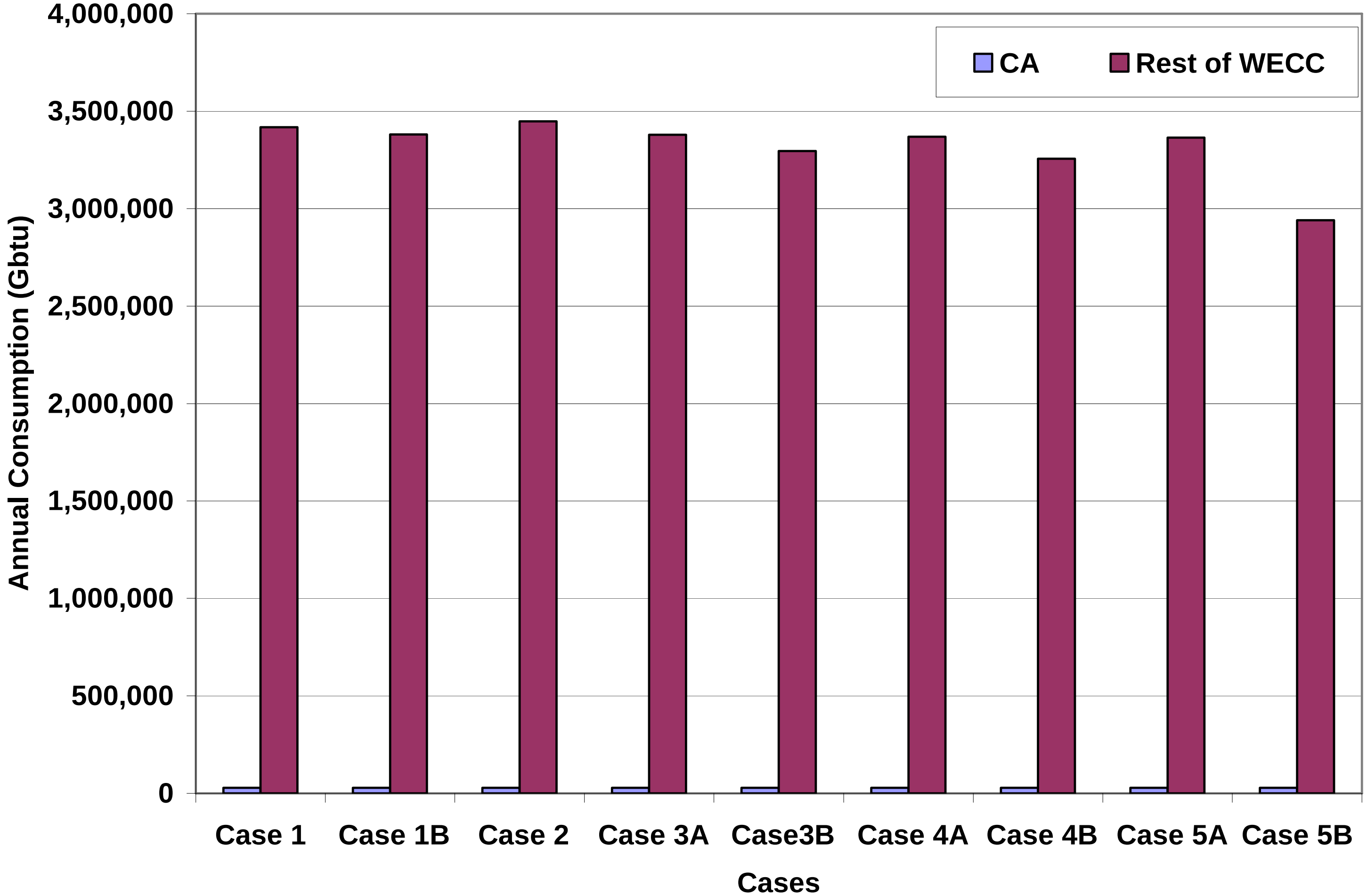


Table 6-17: Coal Consumption Through Time for Each Thematic Case (GBTu)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Case 1												
CA Coal	28,774	28,775	28,777	28,777	28,777	28,777	28,778	28,777	28,778	28,777	28,777	28,778
Rest of WECC Coal	2,930,787	2,980,514	3,123,512	3,126,040	3,132,811	3,138,135	3,173,309	3,201,315	3,236,013	3,309,067	3,343,704	3,417,327
Total WECC Coal	2,959,561	3,009,289	3,152,289	3,154,818	3,161,589	3,166,912	3,202,088	3,230,093	3,264,791	3,337,844	3,372,482	3,446,105
Case 1B												
CA Coal	28,773	28,774	28,777	28,777	28,777	28,777	28,778	28,777	28,778	28,777	28,777	28,778
Rest of WECC Coal	2,926,664	2,976,112	3,083,444	3,085,975	3,091,207	3,096,924	3,132,698	3,159,333	3,196,238	3,270,537	3,307,331	3,380,570
	2,955,437	3,004,886	3,112,222	3,114,753	3,119,984	3,125,702	3,161,476	3,188,110	3,225,016	3,299,315	3,336,109	3,409,347
Case 2												
CA Coal	28,773	28,773	28,777	28,777	28,777	28,777	28,778	28,777	28,778	28,777	28,777	28,778
Rest of WECC Coal	2,930,045	2,984,529	3,136,423	3,140,244	3,141,524	3,142,111	3,178,717	3,210,662	3,276,315	3,349,298	3,380,792	3,448,372
Total WECC Coal	2,958,818	3,013,302	3,165,201	3,169,022	3,170,302	3,170,888	3,207,496	3,239,440	3,305,092	3,378,075	3,409,570	3,477,150
Case 3A												
CA Coal	28,772	28,773	28,777	28,777	28,777	28,777	28,778	28,775	28,778	28,777	28,777	28,778
Rest of WECC Coal	2,926,297	2,975,689	3,083,466	3,084,849	3,090,136	3,095,723	3,131,375	3,157,745	3,194,137	3,268,961	3,305,776	3,379,137
Total WECC Coal	2,955,069	3,004,462	3,112,243	3,113,626	3,118,914	3,124,500	3,160,153	3,186,520	3,222,914	3,297,738	3,334,553	3,407,914
Case 3B												
CA Coal	28,771	28,772	28,777	28,777	28,776	28,775	28,772	28,770	28,775	28,774	28,776	28,775
Rest of WECC Coal	2,924,049	2,969,926	3,053,258	3,052,129	3,052,380	3,058,256	3,089,651	3,111,156	3,142,735	3,217,646	3,223,501	3,295,692
Total WECC Coal	2,952,820	2,998,698	3,082,036	3,080,906	3,081,155	3,087,030	3,118,423	3,139,926	3,171,509	3,246,421	3,252,277	3,324,466
Case 4A												
CA Coal	28,771	28,774	28,777	28,777	28,777	28,777	28,778	28,775	28,778	28,775	28,772	28,774
Rest of WECC Coal	2,926,474	2,975,713	3,083,651	3,085,769	3,091,109	3,095,023	3,129,178	3,153,106	3,188,909	3,261,718	3,298,145	3,368,916
Total WECC Coal	2,955,245	3,004,487	3,112,428	3,114,546	3,119,886	3,123,800	3,157,957	3,181,881	3,217,687	3,290,493	3,326,916	3,397,690
Case 4B												
CA Coal	28,772	28,772	28,777	28,777	28,777	28,777	28,771	28,771	28,763	28,755	28,755	28,752
Rest of WECC Coal	2,926,456	2,975,479	3,064,613	3,062,402	3,070,328	3,071,269	3,098,697	3,118,493	3,141,911	3,208,076	3,203,495	3,256,754
Total WECC Coal	2,955,227	3,004,251	3,093,391	3,091,179	3,099,106	3,100,047	3,127,468	3,147,264	3,170,674	3,236,830	3,232,250	3,285,507
Case 5A												
CA Coal	28,771	28,775	28,777	28,777	28,777	28,777	28,777	28,775	28,774	28,769	28,765	28,770
Rest of WECC Coal	2,926,590	2,976,102	3,083,365	3,085,388	3,089,762	3,093,937	3,128,450	3,151,339	3,187,090	3,258,755	3,295,519	3,364,799
Total WECC Coal	2,955,361	3,004,877	3,112,142	3,114,165	3,118,540	3,122,715	3,157,226	3,180,114	3,215,865	3,287,523	3,324,284	3,393,568
Case 5B												
CA Coal	28,768	28,771	28,777	28,777	28,773	28,772	28,759	28,755	28,667	28,662	28,534	28,447
Rest of WECC Coal	2,924,154	2,969,143	3,052,790	3,045,160	3,044,373	3,036,046	3,020,359	3,015,671	2,999,926	2,990,257	2,961,259	2,940,298
Total WECC Coal	2,952,923	2,997,915	3,081,568	3,073,937	3,073,146	3,064,818	3,049,118	3,044,426	3,028,592	3,018,920	2,989,792	2,968,745

6.2.4 Costs to Electricity Users

This subsection compares the electricity costs (production, incremental capital, and transmission) across the Cases. Three tables of data and two figures are reported. Because different types of resources follow different practices with respect to expensing versus capitalizing costs, and because various resources are added at points in time and then run only short portions of their useful life, a levelized basis is the only means of providing accurate comparisons.

Table 6-18 and Figure 6-22 show the levelized system costs using an 8.6 percent discount rate. System costs include production costs, incremental capital and transmission costs. The levelized system costs show that as more preferred resources are added into the system, California levelized system costs increase.

Table 6-19 shows the differences between Case 1B and each of the cases. Table 6-20 shows the annual system and production costs in 2006 dollars per MWh for California for each case. In general, as more preferred resources are added to the system, production costs show declines, but the capital costs of the preferred resources increase more than production costs decline.

Figure 6-23 shows a comparison of annual production and system costs for California between Case 1 and Case 5A. As both high efficiency and high renewables are added through time in Case 5A, system and production costs diverge from one another quite strongly. Since these costs are annual, and not levelized, they suffer from “end effects” problems and are less meaningful than levelized comparisons. “End effects” encompasses a variety of computational issues arising from limiting the period of analysis to year 2020, even though some resources are added just prior and have useful lives of decades to come.

Table 6-18: Levelized System Costs by Case

	Case 1	Case 1b	Case 2	Case 3a	Case 3b	Case 4a	Case 4b	Case 5a	Case 5b
Total WECC									
Total WECC System Cost ($/MWh) - Levelized 2009-2020	32.94	34.67	41.95	34.63	36.70	35.94	36.63	35.93	38.95
California									
CA System Cost ($/MWh) - Levelized 2009-2020	40.90	46.38	57.38	46.67	46.43	51.14	51.06	51.70	51.29
WECC (excluding California)									
Rest of WECC System Cost ($/MWh) - Levelized 2009-2020	29.12	29.31	34.84	29.20	32.09	29.15	30.16	29.02	33.21

Table 6-19: Comparison of Levelized System Costs (2009–2020)

	Case 1	Case 1B	Difference	% Difference
Total WECC System Cost ($/MWh)	32.94	34.67	1.73	5.2%
California				
CA System Cost ($/MWh)	40.90	46.38	5.48	13.4%
WECC (excluding California)				
Rest of WECC System Cost ($/MWh)	29.12	29.31	0.19	0.7%
	Case 1B	Case 2	Difference	% Difference
Total WECC System Cost ($/MWh)	34.67	41.95	7.28	21.0%
California				
CA System Cost ($/MWh)	46.38	57.38	11.00	23.7%
WECC (excluding California)				
Rest of WECC System Cost ($/MWh)	29.31	34.84	5.52	18.8%
	Case 1B	Case 3A	Difference	% Difference
Total WECC System Cost ($/MWh)	34.67	34.63	-0.04	-0.1%
California				
CA System Cost ($/MWh)	46.38	46.67	0.30	0.6%
WECC (excluding California)				
Rest of WECC System Cost ($/MWh)	29.31	29.20	-0.11	-0.4%
	Case 1B	Case 3B	Difference	% Difference
Total WECC System Cost ($/MWh)	34.67	36.70	2.03	5.9%
California				
CA System Cost ($/MWh)	46.38	46.43	0.05	0.1%
WECC (excluding California)				
Rest of WECC System Cost ($/MWh)	29.31	32.09	2.78	9.5%
	Case 1B	Case 4A	Difference	% Difference
Total WECC System Cost ($/MWh)	34.67	35.94	1.27	3.7%
California				
CA System Cost ($/MWh)	46.38	51.14	4.77	10.3%
WECC (excluding California)				
Rest of WECC System Cost ($/MWh)	29.31	29.15	-0.16	-0.6%
	Case 1B	Case 4B	Difference	% Difference
Total WECC System Cost ($/MWh)	34.67	36.63	1.96	5.6%
California				
CA System Cost ($/MWh)	46.38	51.06	4.68	10.1%
WECC (excluding California)				
Rest of WECC System Cost ($/MWh)	29.31	30.16	0.85	2.9%
	Case 1B	Case 5A	Difference	% Difference
Total WECC System Cost ($/MWh)	34.67	35.93	1.26	3.6%
California				
CA System Cost ($/MWh)	46.38	51.70	5.32	11.5%

WECC (excluding California)				
Rest of WECC System Cost ($/MWh)	29.31	29.02	-0.29	-1.0%
	Case 1B	Case 5B	Difference	% Difference
Total WECC System Cost ($/MWh)	34.67	38.95	4.28	12.3%
California				
CA System Cost ($/MWh)	46.38	51.29	4.91	10.6%
WECC (excluding California)				
Rest of WECC System Cost	29.31	33.21	3.90	13.3%

Note: A discount rate of 8.6 percent was used to levelize the annual system costs between 2009 through 2020.

Figure 6-22 : Levelized System Costs

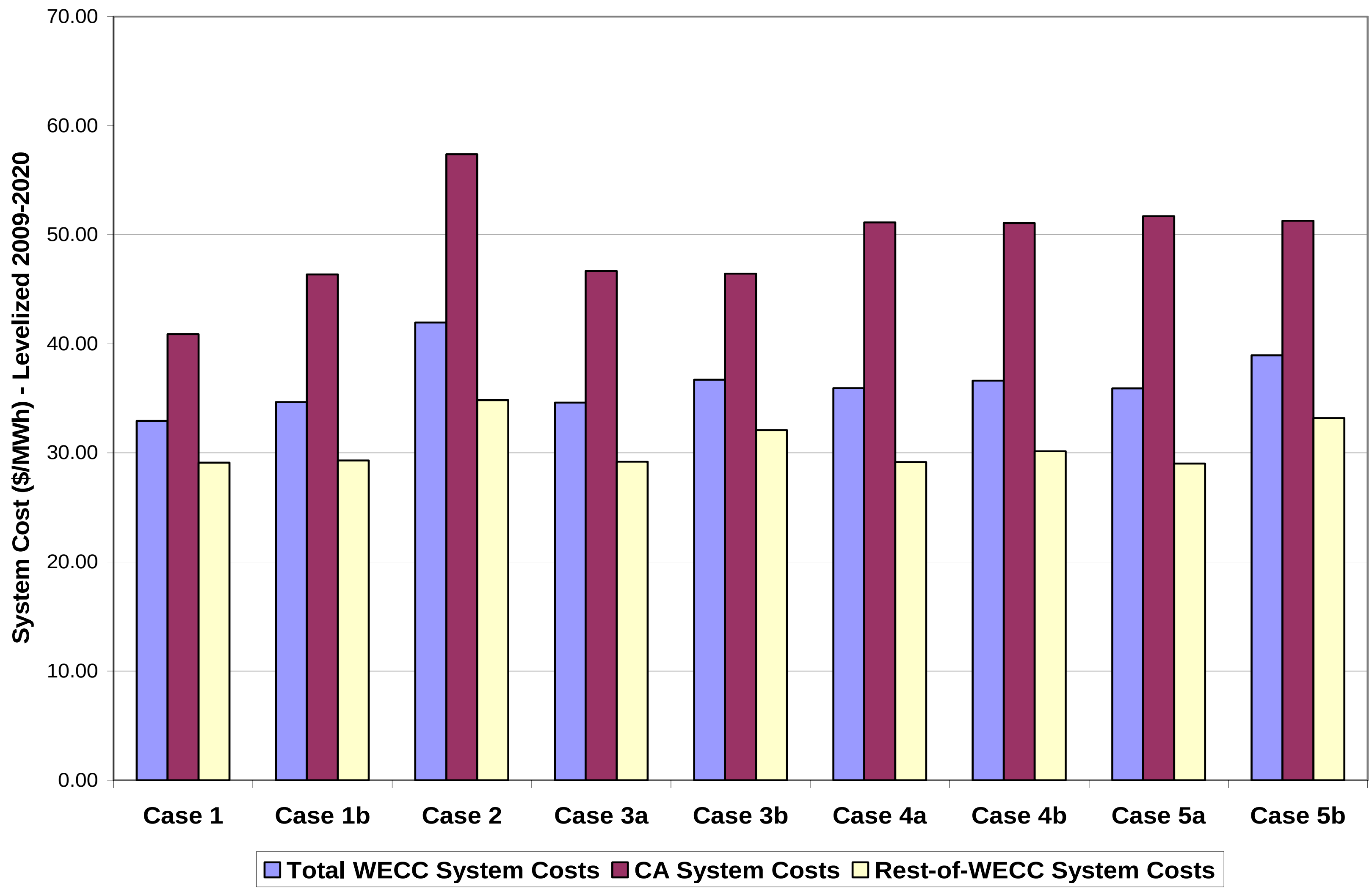
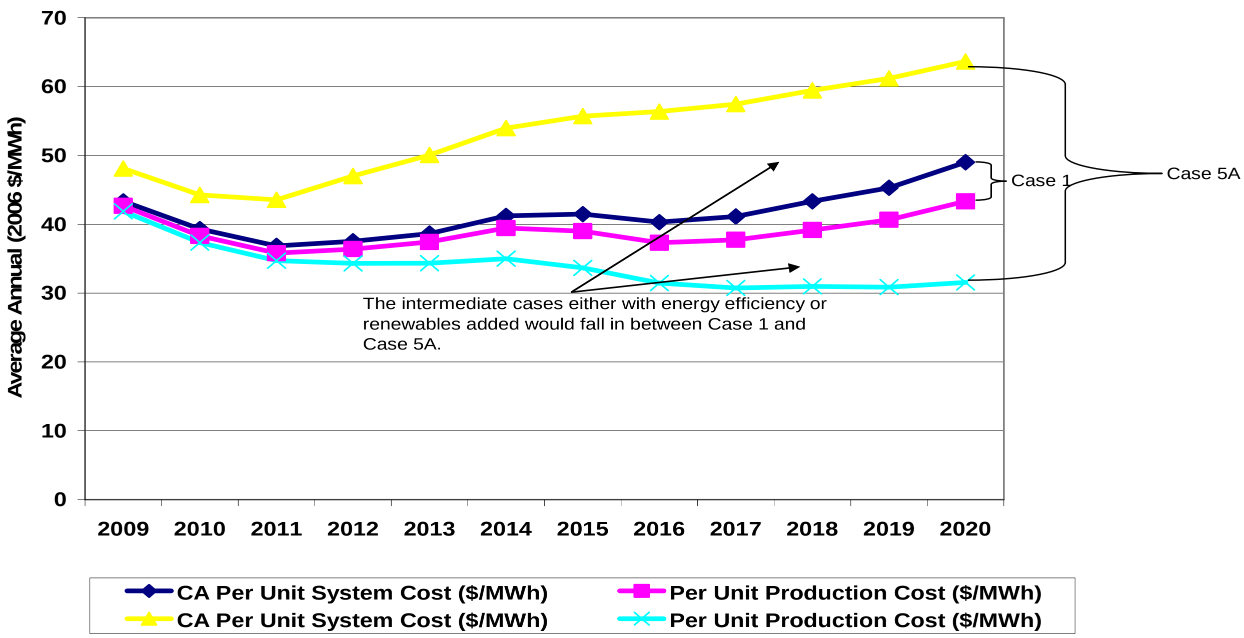


Table 6-20: Annual California Production and System Costs ($2006/MWh)

Case	Cost Type	Levelized System Costs	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Case1	CA Per Unit System Cost	40.90	43.33	39.29	36.86	37.53	38.64	41.21	41.47	40.29	41.13	43.34	45.28	49.00
	Per Unit Production Cost	38.80	42.66	38.31	35.80	36.39	37.42	39.45	39.00	37.32	37.75	39.15	40.64	43.34
Case 1B	CA Per Unit System Cost	46.38	47.44	43.32	40.88	43.50	45.89	48.28	48.16	47.07	47.44	49.01	50.49	53.00
	Per Unit Production Cost	36.31	41.97	37.47	34.89	34.52	34.51	35.93	35.45	33.87	34.08	35.26	36.39	38.55
Case 2	CA Per Unit System Cost	57.38	54.71	53.33	53.67	55.03	55.66	58.16	59.63	62.08	61.26	62.41	62.07	61.37
	Per Unit Production Cost	52.27	50.17	48.77	49.06	50.38	50.99	53.05	54.22	56.43	55.55	56.51	55.94	54.91
Case 3A	CA Per Unit System Cost	46.67	47.69	43.68	41.59	43.79	46.12	48.41	48.40	47.35	47.72	49.27	50.69	53.10
	Per Unit Production Cost	35.90	41.93	37.37	34.75	34.30	34.18	35.50	34.93	33.31	33.40	34.44	35.43	37.43
Case 3B	CA Per Unit System Cost	46.43	47.54	43.51	41.43	43.60	45.88	48.11	48.06	47.08	47.39	48.96	50.33	52.68
	Per Unit Production Cost	35.66	41.78	37.20	34.59	34.11	33.94	35.21	34.60	33.05	33.09	34.14	35.09	37.02
Case 4A	CA Per Unit System Cost	51.14	47.86	43.88	42.85	46.69	49.75	53.61	55.09	55.55	56.58	58.49	60.26	62.68
	Per Unit Production Cost	35.15	41.94	37.44	34.85	34.57	34.66	35.46	34.23	32.11	31.54	31.87	31.99	32.83
Case 4B	CA Per Unit System Cost	51.06	47.87	43.87	42.84	46.64	49.68	53.49	54.94	55.38	56.42	58.31	60.08	62.58
	Per Unit Production Cost	35.07	41.95	37.43	34.84	34.52	34.59	35.33	34.08	31.94	31.37	31.69	31.81	32.73
Case 5A	CA Per Unit System Cost	51.70	48.09	44.26	43.57	47.00	50.07	53.96	55.71	56.37	57.45	59.45	61.20	63.64
	Per Unit Production Cost	34.71	41.88	37.35	34.70	34.32	34.35	35.00	33.67	31.47	30.75	30.96	30.88	31.54
Case 5B	CA Per Unit System Cost	51.29	47.96	44.06	43.39	46.72	49.58	53.35	55.07	55.76	56.81	58.78	60.68	63.06
	Per Unit Production Cost	34.29	41.74	37.15	34.52	34.04	33.87	34.38	33.03	30.86	30.10	30.29	30.35	30.96

Figure 6-23: Unit Cost Comparison Through Time Case 1 versus Case 5A ($2006/MWh)



6.2.5 Other Environmental Measures

This subsection compares the NOx and SOx emissions and water consumption in power generation across the Cases.

Figures 6-24 and 6-25 depict the emissions for 2020. The California emissions for NOx and SO2 from in-state generation remain fairly constant across the cases except NOx emissions decline about 17 percent in 2020 from Case 1B levels to those of Case 5B with high levels of energy efficiency and renewables WECC-wide. A similar pattern is seen in the Rest-of-WECC emissions for NOx and SO2. They remain fairly constant across the cases except in Case 5B they decline about 9 percent from Case 1B levels in 2020. Tables 6-21 and 6-22 provide the data for the figures.

At this level of aggregation, NOx and SO2 are not especially meaningful since the harm these pollutants create is quite specific to airsheds. Increased or decreased emissions of NOx in an airshed already identified with severe smog problems would be much more important than equal emissions in another airshed that did not have smog problems.

The water consumption results are not available at this time and will be available at a later date.

Figure 6-24: California Instate Criteria Pollutant Emissions for NOx and SO2 in 2020 (000 tons)

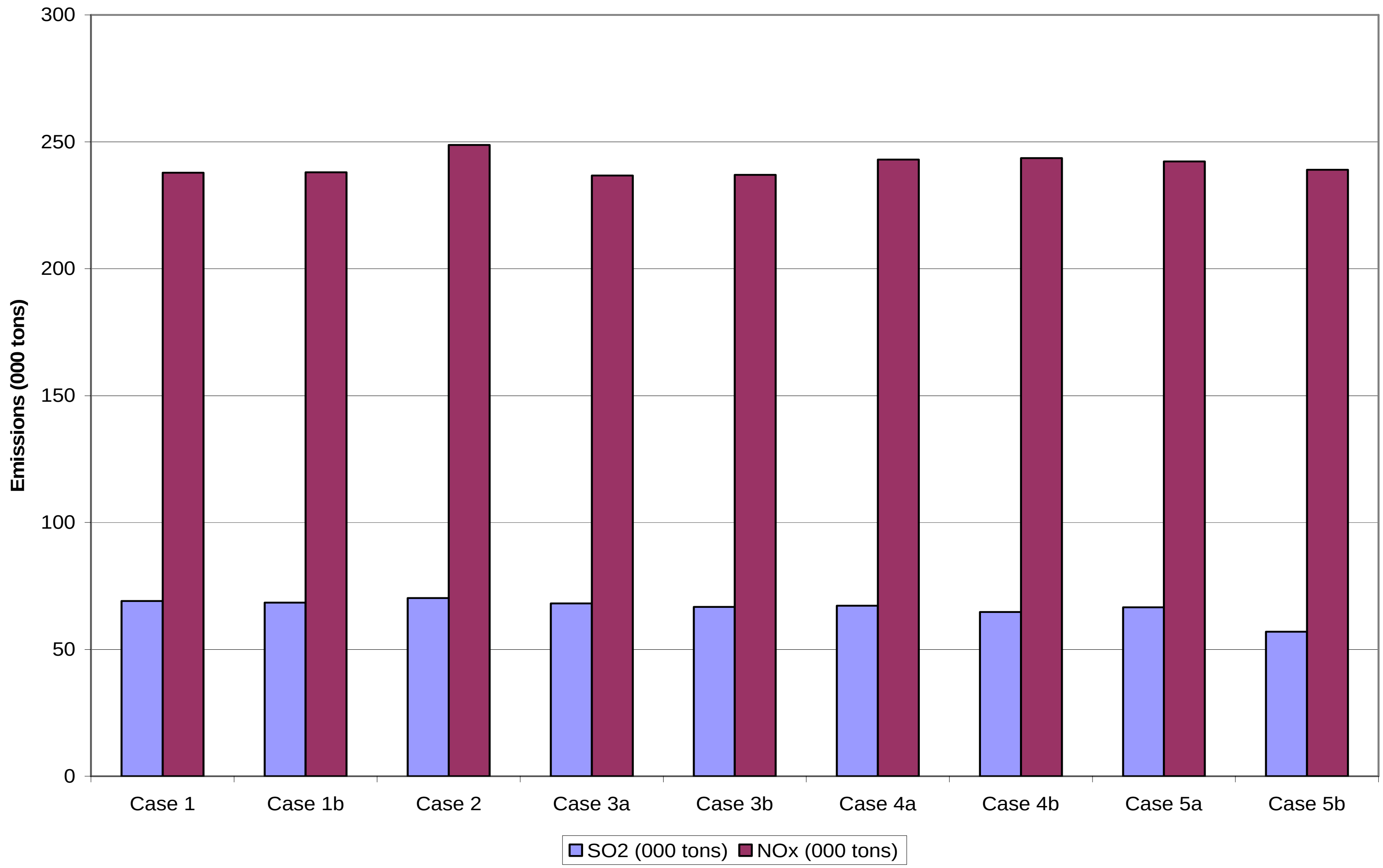


Figure 6-25: Rest-of-WECC Criteria Pollutant Emissions for NOx and SO2 in 2020 (000 tons)

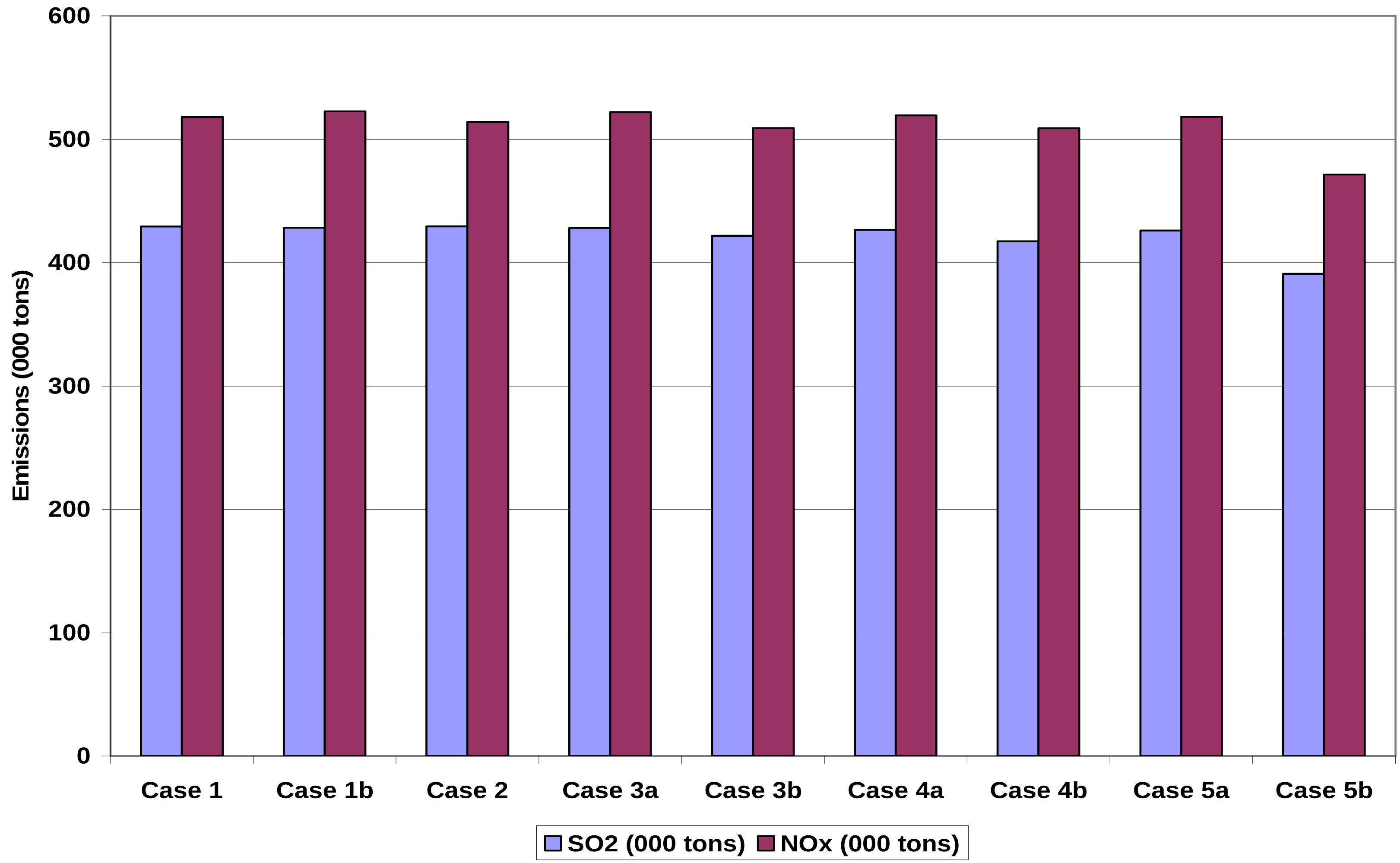


Table 6-21: California Criteria Pollutant Emissions for 2010, 2015, and 2020

	Case 1	Case 1b	Case 2	Case 3a	Case 3b	Case 4a	Case 4b	Case 5a	Case 5b
In-State Generation - 2020									
SO2 (000 tons)	69	68	70	68	67	67	65	67	57
NOx (000 tons)	238	238	249	237	237	243	244	242	239
Remote Generation - 2020									
Remote SO2 (000 tons)	14	14	14	14	14	14	14	14	13
Remote NOx (000 tons)	47	47	46	46	46	46	46	46	42
In-State Generation - 2015									
SO2 (000 tons)	68	67	70	66	65	66	65	66	62
NOx (000 tons)	237	236	253	236	236	238	238	237	236
Remote Generation - 2015									
Remote SO2 (000 tons)	14	14	14	14	14	14	14	14	14
Remote NOx (000 tons)	47	46	46	46	46	46	46	46	46
In-State Generation - 2010									
SO2 (000 tons)	66	66	69	66	65	66	66	66	65
NOx (000 tons)	233	233	236	233	233	233	234	233	233
Remote Generation - 2010									
Remote SO2 (000 tons)	14	14	14	14	14	14	14	14	14
Remote NOx (000 tons)	46	46	46	46	46	46	46	46	46

Table 6-22: Rest-of-WECC Criteria Pollutant Emissionsfor 2010, 2015, and 2020

	Case 1	Case 1b	Case 2	Case 3a	Case 3b	Case 4a	Case 4b	Case 5a	Case 5b
Rest-of-WECC Generation - 2020									
SO2 (000 tons)	402	402	403	401	395	400	391	399	366
NOx (000 tons)	457	462	453	461	449	459	449	458	415
Remote Generation - 2020									
Remote SO2 (000 tons)	27	27	27	27	27	27	27	27	25
Remote NOx (000 tons)	61	61	61	61	61	61	60	61	57
Rest-of-WECC Generation - 2015									
SO2 (000 tons)	416	415	418	414	410	414	412	414	403
NOx (000 tons)	445	448	444	447	439	447	444	446	432
Remote Generation - 2015									
Remote SO2 (000 tons)	27	27	27	27	27	27	27	27	26
Remote NOx (000 tons)	61	61	61	61	61	61	61	61	60
Rest-of-WECC Generation - 2010									
SO2 (000 tons)	411	411	413	410	409	410	410	411	409
NOx (000 tons)	433	434	433	434	432	434	434	434	431
Remote Generation - 2010									
Remote SO2 (000 tons)	27	27	27	27	27	27	27	27	27
Remote NOx (000 tons)	61	61	61	61	61	61	61	61	61

6.2.6 Transarea Results

This section provides an overview of the physical generation result for the full set of transareas by abstracting from the transarea scorecards that will be in an appendix. This is the format that best allows a comparison of actual generation changes in each of the transareas across WECC. Some commentary to identify interesting observations is appropriate, but the scope will depend upon the results.

Appendix D-1 provides more detailed results for each of the 29 transareas across the cases.

CHAPTER 7: DETERMINING THE IMPLICATIONS FOR EACH STRATEGY FOR THE PREFERRED RESOURCE TYPES

This chapter compares the various cases that reveal the differential results for each of the preferred resource types. The PROSYM datasets were set up so that the preferred resource input assumptions carry through largely as the results for those resource types, but the many other variables change through the results of the simulation. By comparing cases with and without the specific preferred resource assumptions, the impacts of the assumed levels of penetrations of the preferred resources can be estimated.

This section addresses the following sets of case to case comparisons. These discussions use the detailed results included in Appendix C for each of the sets of cases described:

- High levels of energy efficiency in California only can be assessed by comparing Cases 3A and 1B;
- High levels of supply-side renewables in California only can be assessed by comparing Case 4A with Case 1B;
- High levels of both energy efficiency and supply-side in California only generating technologies can be assessed by comparing Cases 5A and 1B;
- High levels of energy efficiency in Rest-of-WECC can be assessed by comparing Cases 3B and 3A.;
- High levels of supply-side renewable generating technologies in Rest-of-WECC can be assessed by comparing Cases 4B and 4A.; and
- High levels of both energy efficiency and supply-side renewable generating technologies in Rest-of-WECC can be assessed by comparing Cases 5B and 5A.

Each section of this chapter discusses a single one of these comparisons. Each section uses three tables to show the key results of the analysis. One table shows the differences in generation as computed by the model for both 2015 and 2020. A second table reports changes in costs for those cost categories included in the analysis for these same two years. A third table provides a comparison of the carbon emissions for California and the Rest-of-WECC.

The table explaining generating system impacts draws upon the detail results of the simulations to quantify the consequences of the assumptions as the PROSYM production cost model determines them. PROSYM is focused, above all else, on the question of dispatch of resources in a least cost paradigm, subject to a variety of constraints. Since the energy efficiency and most renewables are modeled as load modifiers or must take resources, respectively, what has been assumed becomes a result.

The dispatchable resources, largely natural gas-fired facilities and coal—with minor changes from a few smaller categories of resources—are the only ones the model is allowed to change. The tables in this chapter show them as the changes resulting from the assumptions.

The table showing cost differences encompasses all of the elements normally included in production costs. It shows only some elements of capital cost and excludes existing plants and those additions that are assumed to be in common across all cases. [See Section 3.3 for an explanation of what is included and excluded.] These limitations do not affect the ability to compare values between cases, because the missing capital cost elements are common to all cases. Since they are missing from all cases and the values are equal in all cases, this omission does not distort the ability to estimate the total cost differences between the cases.

As noted in earlier chapters, the California responsibility for carbon consists of three categories: (1) power plants located in California, (2) power plants owned by or under long term contract to California LSEs, and (3) emissions from power plants located outside of California that correspond to "imports." Similarly, the Rest-of-WECC carbon emissions consist of the plants located in Rest-of-WECC serving Rest-of-WECC loads as well as the share of the remote plants serving Rest-of-WECC loads. The third table in each section provides a comparison showing these details, since sourcing of power, and thus carbon emissions, differs from case to case all across the West.

7.1 Energy Efficiency in California Only—Comparing Cases 3A and 1B

As described previously, Case 3A assumes an expansion of energy efficiency compared to Case 1B in California alone. The expansion is sized to shift up to the economic potential values from the 2006 Itron report. The incremental costs and consequences of the high energy efficiency preferred resources for California alone can be determined by comparing Cases 1B and 3A.

Table 7-1 selects those values from the aggregated scorecard for California that highlight the input changes and the predicted results. The results reveal that increased energy efficiency displaces both California generation (almost entirely gas-fired generation) and imports generated by power plants in Rest-of-WECC (almost entirely natural gas). The predicted decreases are approximately two thirds in California and one third in Rest-of-WECC, both in 2015 and 2020. Clearly these results suggest that some portion of the load displaced by energy efficiency is imports into California, apparently almost entirely from natural gas plants.

There are several perspectives to use in looking at the financial implications of this high efficiency strategy. First, there are production cost decreases of amounting to several hundred million dollars per year as one would expect since less fossil fuel is being burned. Ranged against this are energy efficiency program expenditures, as well as any unsubsidized expenditures by program participants. Table 7-2 reports program expenditures and direct system costs in each of years 2015 and 2020. There is a decrease in total system costs in 2015, but an increase for 2020. The scorecard results included in Appendix C provide the comparable details for these cost categories for other years. Appendix F provides greater details about the energy efficiency impacts and costs as they were abstracted from the Itron potential study.

Table 7-3 follows the general pattern of Table 7-1, e.g. carbon emissions decline both from reduced operation of power plants in California and from reduction in imports. Rest-of-WECC emissions actually increase a small amount as power plant there are dispatched differently. Overall, energy efficiency implemented just in California reduces carbon emissions throughout the entire Western Interconnection.

Table 7-1: Generating System Changes in Response to Increased California Energy Efficiency*

	California Generation (GWh)		Rest-of-WECC Generation (GWh)	
Resource Type	Assumed Increases	Predicted Decreases	Assumed Increases	Predicted Decreases
Year 2015				
EE	6596	0	0	0
Gas Fired	0	4037	0	2448
Coal	0	0	0	46
Pumped Storage	0	97	0	-6
Year 2020				
EE	12625	0	0	0
Gas Fired	0	8620	0	4138
Coal	0	0	0	119
Pumped Storage	0	167	0	-4

*Increases and decreases in resources do not balance exactly because losses change as the source of generation changes between cases.

Table 7-2: Projected Costs of High Energy Efficiency Case in California Only

	Projected Costs for California (2006 $ Billion)		
Cost Component	Case 1B	Case 3A	Difference
2015			
System Costs	14.6	14.3	-0.3
Production Costs	10.7	10.4	-0.3
EE Program Expenses	1.1	1.3	0.2
Generation Capital	1.7	1.7	0
Transmission Upgrades	0.3	0.4	0.1
2020			
System Costs	16.4	15.7	-0.7
Production Costs	11.9	11.1	-0.8
EE Program Costs	1.1	1.3	0.2
Generation Capital	2.3	2.2	-0.1
Transmission Upgrades	0.3	0.4	0.1

Table 7-3: Carbon Emission Impacts from High Energy Efficiency in California Only

	2020 Carbon (000 tons)		
Region/Category	Case 1B	Case 3A	Difference
CA			
CA CO2 Production	63,907	60,032	-3,876
CA Remote* CO2	27,087	27,048	-38
CA Import CO2	16,982	14,572	-2,410
Rest of WECC			
Rest of WECC CO2 Production	354,757	355,389	632
Rest of WECC Remote* CO2	36,294	36,247	-47
WECC			
CA (includes remote* and Imports)	107,976	101,652	-6,324
Rest of WECC (includes remote*)	391,051	391,637	585
Total WECC	499,027	493,289	-5,738

7.2 High Renewables in California Only–Comparing Cases 4A and 1B

The incremental costs and consequences of the high renewables and solar rooftop PV for California alone can be determined by comparing Cases 1B and 4A. The inputs for Case 4A are only higher supply-side renewables and rooftop PV in California. Table 7-4 shows that these increases are distributed among a variety of renewable technologies. The level of renewables also increases rapidly between 2015 and 2020.

The results shown in Table 7-4 for energy production reveal that increased renewables (supply-side generating technologies and distributed generation in the form of rooftop PV) displaced both California generation and Rest-of-WECC generation. Broadly, this was the same result discussed in the previous subsection for assumed energy efficiency strategy. Like the energy efficiency cases, natural gas resources in both California and Rest-of-WECC are the principal generating technology that is displaced. Unlike the energy efficiency case, the mix between California and Rest-of-WECC is much more balanced. For this renewable strategy, almost equal displacement of natural gas-fired electricity production takes place, unlike the domination of greater impact on instate generation that was found for the energy efficiency case.

Unlike the energy efficiency case, this renewables case shows an increase in total California electricity costs compared to the projections of Case 1B. Production costs show declines, but the capital costs of renewable resources (both rooftop PV and supply-side generating technologies) increases more than the production costs decline. Rooftop PV is a major element of these capital cost increases. Appendix C provides the detailed scorecard results, but Table 7-5 provides a few results for years 2015 and 2020.

Since the incremental resources for Case 4A are installed largely beginning in 2013 and through 2020, the resources will have useful lives for many more years than the end date for this analysis. Should the end date of the analysis have been shifted out to 2030, as some parties commenting at an earlier workshop had suggested, then these results would look more favorable for renewable technologies. Section 10.3 of this report addresses this issue in more detail.

Table 7-5 provides the results of the assessment of carbon emissions from this high renewables in California strategy. It has results that are similar in pattern to those of the high efficiency strategy, but the scale of the changes is larger. California and the Western Interconnection as a whole have reduced carbon emissions from this strategy.

Table 7-4: Generating System Changes in Response to High California-Only Renewable Development*

	California Generation (GWh)		Rest-of-WECC Generation (GWh)	
Resource Type	Assumed Increases	Predicted Decreases	Assumed Increases	Predicted Decreases
Year 2015				
Wind	2753	0	0	0
Geothermal	4166	0	0	0
Biomass	1441	0	0	0
Central Solar	163	0	0	0
Rooftop PV	5918	0	0	0
Gas Fired	0	7898	0	5879
Coal	0	0	0	298
Pumped Storage	0	88	0	0
Year 2020				
Wind	14407	0	0	0
Geothermal	13156	0	0	0
Biomass	5317	0	0	0
Central Solar	4095	0	0	0
Rooftop PV	6407	0	0	0
Gas Fired	0	21489	0	19660
Coal	0	0	0	937
Pumped Storage	0	155	0	0

*Increases and decreases in resources do not balance exactly because losses change as the source of generation changes between cases.

Table 7-5: Projected Costs of High Renewable Case in California Only

	Projected Costs for California (2006 $ Billion)		
Cost Component	Case 1B	Case 4A	Difference
2015			
System Costs	14.6	16.4	1.8
Production Costs	10.7	10.1	-0.6
Rooftop PV Costs	0.5	2.5	2.0
Generation Capital	1.7	2.1	0.4
Transmission Upgrades	0.3	0.4	0.1
2020			
System Costs	16.4	18.9	2.5
Production Costs	11.9	9.9	-2.0
Rooftop PV Costs	0.6	3.0	2.4
Generation Capital	2.3	4.4	2.1
Transmission Upgrades	0.3	0.4	0.1

Table 7-6: Carbon Emission Impacts from High Renewables in California Only

	2020 Carbon (000 tons)		
Region/Category	Case 1b	Case 4a	Difference
CA			
CA CO2 Production	63,907	58,078	-5,829
CA Remote* CO2	27,087	26,843	-244
CA Import CO2	16,982	4,970	-12,012
Rest of WECC			
Rest of WECC CO2 Production	354,757	357,924	3,167
Rest of WECC Remote* CO2	36,294	35,932	-362
WECC			
CA (includes remote* and Imports)	107,976	89,891	-18,085
Rest of WECC (includes remote*)	391,051	393,856	2,805
Total WECC	499,027	483,747	-15,280

7.3 Combined Strategy for California – Comparing Case 5A with Case 1B

The incremental effect of high levels of both energy efficiency, rooftop solar PV, and central station renewables, implemented strictly in California, can be determined by comparing cases 1B with Case 5A. As one can determine intuitively, adding both of these classes of preferred resource addition leads to the lowest GHG projections of any of the California-only cases.

Table 7-7 provides an extract from the more detailed scorecard results contained in Appendix C. The pattern of displaced natural gas generation in both California and in Rest-of-WECC revealed in the results of previous analyses for energy efficiency and renewables shows up once again. A small amount of Rest-of-WECC coal imports are also displaced. Roughly half of the displaced fossil generation is located in California and one half in Rest-of-WECC. Clearly natural gas facilities are the ones at the top of the dispatch order.

Table 7-8 provides an assessment of the financial implications of this combined strategy in California alone. The results are very similar to simply adding the effects reported in each of Tables 7-2 and 7-5 together. Thus, the increased capital costs of renewables increases total system costs, even though production costs decline. As noted in the previous subsection, the end effects of heavy capital expenditures for resources that have useful lives far beyond year 2020 distorts the apparent conclusion that renewables are not a good choice. The very high costs of rooftop PV contribute to this result just as they do in the previous subsection addressing renewables alone.

Table 7-9 provides the results of pursuing both high energy efficiency and high renewables in California alone, with results that resemble the addition of the results of the two previous strategies. The largest reduction in California's carbon responsibility comes from reduction in carbon from imports.

Table 7-7: Generating System Changes in Response to High California-Only Combined Energy Efficiency and Renewable Development*

	California Generation (GWh)		Rest-of-WECC Generation (GWh)	
Resource Type	Assumed Increases	Predicted Decreases	Assumed Increases	Predicted Decreases
Year 2015				
Energy Efficiency	6,596	0	0	0
Wind	2,753	0	0	0
Geothermal	4,166	0	0	0
Biomass	1,441	0	0	0
Central Solar	163	0	0	0
Rooftop PV	5,918	0	0	0
Gas Fired	0	11,737	0	8,453
Coal	0	0	0	351
Pumped Storage	0	158	0	0
Year 2020				
Energy Efficiency	12,625	0	0	0
Wind	14,407	0	0	0
Geothermal	13,156	0	0	0
Biomass	5,317	0	0	0
Central Solar	4,095	0	0	0
Rooftop PV	6,407	0	0	0
Gas Fired	0	28,663	0	24,534
Coal	0	0	0	1,259
Pumped Storage	0	205	0	0

*Increases and decreases in resources do not balance exactly because losses change as the source of generation changes between cases.

Table 7-8: Projected Costs of Combined High Efficiency and High Renewable Case in California Only

	Projected Costs for California (2006 $ Billion)		
Cost Component	Case 1B	Case 5A	Difference
2015			
System Costs	14.6	16.2	1.6
Production Costs	10.7	9.8	-0.9
EE Program Costs	1.1	1.3	0.2
Rooftop PV Costs	0.5	2.5	2.0
Generation Capital	1.7	2.1	0.4
Transmission Upgrades	0.3	0.4	0.1
2020			
System Costs	16.4	18.4	2.0
Production Costs	11.9	9.1	-2.8
EE Program Costs	1.1	1.3	0.2
Rooftop PV Costs	0.6	3.0	2.4
Generation Capital	2.3	4.4	2.1
Transmission Upgrades	0.3	0.4	0.1

Table 7-9: Carbon Emission Impacts from High Energy Efficiency and Renewables in California Only

	2020 Carbon (000 tons)		
Region/Category	Case 1B	Case 5A	Difference
CA			
CA CO2 Production	63,907	54,836	-9,071
CA Remote* CO2	27,087	26,777	-310
CA Import CO2	16,982	1,934	-15,048
Rest of WECC			
Rest of WECC CO2 Production	354,757	358,607	3,850
Rest of WECC Remote* CO2	36,294	35,840	-454
WECC			
CA (includes remote* and Imports)	107,976	83,547	-24,429
Rest of WECC (includes remote*)	391,051	394,447	3,396
Total WECC	499,027	477,994	-21,033

7.4 Energy Efficiency in Rest-of-WECC – Comparing Cases 3B and 3A

The incremental effect of achieving high levels of energy efficiency in Rest-of WECC can be determined by comparing Cases 3A and 3B. Case 3B has inputs that differ from Case 3A only by adding additional energy efficiency in Rest-of-WECC, so comparing Case 3B back to Case 3B allows a direct computation of generation displaced by Rest-of-WECC energy efficiency impacts on load. Comparing back to Case 3A, however, does assume that California makes the primary commitment to energy efficiency and that Rest-of-WECC would not pursue a high efficiency strategy when California does not.

Table 7-10 provides a summary of the changes in generation that result from Case 3B. These changes take two forms: (1) displacement of electricity production from existing facilities and deferral or avoidance of planned generation additions. As was found in the California only Case 3A, this Case 3B indicates that natural gas-fired generation decreases most in response to lower demand as energy efficiency reduces load. Some coal generation also decreases. Unlike the California only case, however, Rest-of-WECC generation does not decrease by the full amount of energy efficiency programs assumed for Rest-of-WECC. California imports more from Rest-of-WECC since the model dispatches the lower cost Rest-of-WECC resources in preference to more expensive California resources as long as transmission capacity exists to do so. The limited set of values reported in Table 7-10 is supported in more detail with the data contained in Appendix C.

Table 7-11 provides an assessment of the cost implications for this high energy efficiency strategy implemented in Rest-of-WECC. This cost assessment is from the perspective of the entities paying the bill for electricity in Rest-of-WECC. In the near term, the costs and savings just about balance out. By 2020, however, the accumulated benefits of the investments in energy efficiency create greater and greater production cost savings, with a net beneficial impact on electricity end-users in Rest-of-WECC. As noted in previous subsections of this chapter, a focus on just 2015 or just 2020 can be misleading, since the rapid changes in the period between 2015 and 2020 have consequences for the period following 2020. These “end effects” have not been assessed.

Table 7-12 has changes in Rest-of-WECC carbon emissions of a larger scale than the corresponding strategy for California simply because loads in Rest-of-WECC are much larger in aggregate than California. As noted in the discussion for Table 7-10, carbon responsibility for California actually increases compared to the California energy strategy because imports increase a great deal. In total, the Western Interconnection drops substantially even though California increases.

Table 7-10: Generating System Changes in Response to Increased Energy Efficiency in Rest-of-WECC and California*

	California Generation (GWh)		Rest-of-WECC Generation (GWh)	
Resource Type	Assumed Increases	Predicted Decreases	Assumed Increases	Predicted Decreases
Year 2015				
EE	0	0	48,070	0
Gas Fired	0	5,003	0	34,729
Coal	0	0	0	4,061
Pumped Storage	0	4	0	31
Other	0	0	0	
Imports to CA	0	-8,418	0	0
Exports from RofW	0	0	0	-8,418
Year 2020				
EE	0	0	82,408	0
Gas Fired	0	13,396	0	58,840
Coal	0	0	0	8,381
Pumped Storage	0	-11	0	54
Other	0	0	0	173
Imports to CA	0	-13,958	0	0
Exports from RofW	0	0	0	-13,958

*Increases and decreases in resources do not balance exactly because losses change as the source of generation changes between cases.

Table 7-11: Projected Costs of High Energy Efficiency Case in Rest-of-WECC and in California

	Projected Costs For Rest-of-WECC (2006 $ Billion)		
Cost Component	Case 3A	Case 3B	Difference
2015			
System Costs	21.3	21.4	0.1
Production Costs	16.3	14.7	-1.6
EE Program Expenses	0	2.5	2.5
Generation Capital	3.7	2.9	-0.8
Transmission Upgrades	1.1	1.1	0
2020			
System Costs	27.3	24.9	-2.4
Production Costs	19.8	16.6	-3.2
EE Program Costs	0	2.5	2.5
Generation Capital	6.1	4.4	-1.7
Transmission Upgrades	1.2	1.2	0

Table 7-12: Carbon Emission Impacts from High Energy Efficiency in Rest-of-WECC and California

	2020 Carbon (000 tons)		
Region/Category	Case 3A	Case 3B	Difference
CA			
CA CO2 Production	60,032	54,868	-5,164
CA Remote* CO2	27,048	26,755	-293
CA Import CO2	14,572	22,671	8,099
Rest of WECC			
Rest of WECC CO2 Production	355,389	313,679	-41,710
Rest of WECC Remote* CO2	36,247	35,782	-465
WECC			
CA (includes remote* and Imports)	101,652	104,294	2,642
Rest of WECC (includes remote*)	391,637	349,461	-42,175
Total WECC	493,289	453,755	-39,533

7.5 Supply-Side Renewables in Rest-of-WECC and California – Comparing Cases 4B and 4A

The incremental costs and consequences of the high renewables case throughout the West can be determined by comparing Cases 4A and 4B. Case 4A is high renewables for California alone, while Case 4B maintains the same renewables in California and extends the concept of high renewable development to the Rest-of-WECC.

Table 7-13 shows the mix of assumed renewable development in years 2015 and 2020 that were added in the Rest-of-WECC region in Case 4B. Wind, geothermal, and biomass are added in that order. The relative proportion among these technologies does not change through time even though the magnitudes of annual production increase quite strongly during this five-year period. As has been seen in the previous cases examining energy efficiency and renewables in California and energy efficiency in Rest-of-WECC, the great majority of predicted reductions to accommodate the renewables are in natural gas-fired generation. A much smaller amount of electricity from coal is also reduced, and this is a small percentage of overall coal generation in Rest-of-WECC.

The results of the production cost assessment also show that California imports greater levels of Rest-of-WECC generation since renewable capacity in Rest-of-WECC frees up cheaper conventional resources that are dispatched to satisfy California loads rather than more expensive California resources. This is the same general conclusion that was reached for a high efficiency strategy in Rest-of-WECC, as can be seen in Table 7-10, but the size of the effect is smaller.

Table 7-14 shows the cost implications for Rest-of-WECC that electricity end-users might be expected to accommodate. The capital cost values for the technologies and associated transmission increase more than the production cost values decrease, leading to an overall cost increase. These increases are small in the context of the total generation system costs for the Rest-of-WECC region. In addition, the "end effects" noted in previous sections also make the results more negative than a longer-term assessment would conclude.

Table 7-15 provides the results of the high renewables strategy in Rest-of-WECC paralleling its implementation in California. Like the high energy efficiency strategy, California emissions of carbon actually increase while the total from the Western Interconnection decrease. These effects are not quite as large as for the energy efficiency strategy, but the pattern is identical.

Table 7-13 Generating System Changes in Response to High Renewable Development in Rest-of-WECC and California*

	California Generation (GWh)		Rest-of-WECC Generation (GWh)	
Resource Type	Assumed Increases	Predicted Decreases	Assumed Increases	Predicted Decreases
Year 2015				
Wind	0	0	18,655	0
Geothermal	0	0	4,465	0
Biomass	0	0	2,020	0
Central Solar	0	0	0	0
Rooftop PV	0	0	164	0
Gas Fired	0	4,491	0	17,336
Coal	0	0	0	3,047
Pumped Storage	0	33	0	-13
Imports to CA	0	-4,648	0	0
Exports from RofW	0	0	0	-4,648
Year 2020				
Wind	0	0	45,061	0
Geothermal	0	0	11,415	0
Biomass	0	0	5,809	0
Central Solar	0	0	0	0
Rooftop PV	0	0	790	0
Gas Fired	0	10,619	0	40,283
Coal	0	0	0	10,590
Pumped Storage	0	5	0	-94
Imports to CA	0	-11,315	0	0
Exports from RofW	0	0	0	-11,315

*Increases and decreases in resources do not balance exactly because losses change as the source of generation changes between cases.

Table 7-14 Projected Costs of High Renewable Case in Rest-of-WECC and in California

	Projected Costs For Rest-of-WECC (2006 $ Billion)		
Cost Component	Case 4A	Case 4B	Difference
2015			
System Costs	21.2	22.1	0.9
Production Costs	16.1	15.4	-0.7
Rooftop PV Costs	0.2	0.2	0
Generation Capital	3.6	4.8	1.2
Transmission Upgrades	1.3	1.7	0.4
2020			
System Costs	26.5	28.6	2.1
Production Costs	19.0	17.1	-1.9
Rooftop PV Costs	0.2	0.5	0.3
Generation Capital	6.0	8.7	2.7
Transmission Upgrades	1.3	2.4	1.1

Table 7-15: Carbon Emission Impacts from High Renewables in Rest-of-WECC and California

	2020 Carbon (000 tons)		
Region/Category	Case 4A	Case 4B	Difference
CA			
CA CO2 Production	58,078	54,172	-3,906
CA Remote* CO2	26,843	26,314	-528
CA Import CO2	4,970	10,451	5,481
Rest of WECC			
Rest of WECC CO2 Production	357,924	326,713	-31,212
Rest of WECC Remote* CO2	35,932	35,390	-542
WECC			
CA (includes remote* and Imports)	89,891	90,938	1,047
Rest of WECC (includes remote*)	393,856	362,102	-31,754
Total WECC	483,747	453,040	-30,707

7.6 Combined Strategy in Rest-of-WECC and California – Comparing Cases 5B and Case 5A

The incremental effect of high levels of both energy efficiency and supply-side renewables can be determined by comparing cases 5B and 5A. As one can determine intuitively, adding both of these classes of preferred resource addition leads to the lowest GHG projections for WECC or Rest-of-WECC of any of the Cases.

Table 7-16 provides the predicted generating system changes in conjunction with the assumptions about energy efficiency and renewables that were included incrementally in Case 5B compared to Case 5A. A familiar story emerges again. The energy efficiency reductions to load and the "must take" quality of nearly all of the renewables means that large reductions in the dispatchable resources will occur. The greater majority of the reductions take place in Rest-of-WECC natural gas-fired generation. The model also predicts that some reductions in Rest-of-WECC coal will occur, although this is a small quantity in percentage terms. As was seen in early sections of this chapter, California resources are also displaced, again almost exclusively California natural gas-fired resources. To sum up, Rest-of-WECC dispatchable resources are displaced less than the sum of the energy efficiency impacts on load and the renewable generation because some California generation is displaced and California imports more than it would with the same set of resources it had in Case 5A.

Table 7-17 provides a summary of the cost implications of both high energy efficiency and high renewables in Rest-of-WECC. Individual cost factors are moving in different directions, resulting in relatively small increases in total system costs in the two years reported. Production costs are down sharply in year 2020 as would result from more than 130,000 GWh of generation being added that has no fuel costs. Paying for these resources involves capital investment that must be amortized and a rate of return provided to investors. The reported results show that the direct investments in these two years lead to total generation cost increases. Once again, however, this effect is more pessimistic than a complete life-cycle costing analysis would provide, since some investments are made near the end of the period and have useful lives far beyond the 2020 terminal year of this analysis. This "end effect" is discussed in Chapter 10.3 as an element of the analysis that should be improved.

Table 7-18 shows major reductions in total carbon for the West as a whole, but again California imports much more power that is cheaper to operate than plants in its own borders, thus increasing carbon emissions drastically compared to the case of pursuing high efficiency and renewables on its own, while the Rest-of-WECC does not. Section 10.1 discusses additional analysis that would have to be conducted to develop a more complete approach to changing the coal capacity that exists and that is in the construction pipeline today.

Table 7-16: Generating System Changes in Response to Combined High Energy Efficiency and High Renewable Development in Rest-of-WECC and California*

	California Generation (GWh)		Rest-of-WECC Generation (GWh)	
Resource Type	Assumed Increases	Predicted Decreases	Assumed Increases	Predicted Decreases
Year 2015				
Energy Efficiency	0	0	48,070	0
Wind	0	0	18,655	0
Geothermal	0	0	4,465	0
Biomass	0	0	725	0
Central Solar	0	0	1,344	0
Rooftop PV	0	0	165	0
Gas Fired	0	13,811	0	46,706
Coal	0	0	0	10,310
Pumped Storage	0	20	0	16
Fuel Oil	0	-9	0	-11
Imports to CA	0	-14,671	0	0
Exports from RofW	0	0	0	-14,671
Year 2020				
Energy Efficiency	0	0	82,448	0
Wind	0	0	45,061	0
Geothermal	0	0	11,415	0
Biomass	0	433	2.950	0
Central Solar	0	0	2,904	0
Rooftop PV	0	0	790	0
Gas Fired	0	23,132	0	75,545
Coal	0	37	0	38,752
Pumped Storage	0	7	0	-5-
Fuel Oil	0	-32	0	-52
Imports to CA	0	-26,348	0	0
Exports from RofW	0	0	0	-26,348

*Increases and decreases in resources do not balance exactly because losses change as the source of generation changes between cases.

Table 7-17: Projected Costs of Combined High Efficiency and High Renewable Case in Rest-of-WECC and California

	Projected Costs for Rest-of-WECC (2006 $ Billion)		
Cost Component	Case 5A	Case 5B	Difference
2015			
System Costs	21.1	22.2	1.1
Production Costs	16.0	13.8	-2.2
EE Program Costs	0	2.5	2.5
Rooftop PV Costs	0.2	0.2	0
Generation Capital	3.6	3.9	0.3
Transmission Upgrades	1.3	1.8	0.5
2020			
System Costs	26.3	26.9	0.6
Production Costs	18.8	14.3	-4.5
EE Program Costs	0	2.5	2.5
Rooftop PV Costs	0.2	0.5	0.3
Generation Capital	6.0	7.1	1.1
Transmission Upgrades	1.3	2.5	1.2

Table 7-18: Carbon Emission Impacts from High Energy Efficiency and Renewables in Rest-of-WECC and California

	2020 Carbon (000 tons)		
Region/Category	Case 5A	Case 5B	Difference
CA			
CA CO2 Production	54,836	46,356	-8,480
CA Remote* CO2	26,777	24,257	-2,520
CA Import CO2	1,934	14,932	12,998
Rest of WECC			
Rest of WECC CO2 Production	358,607	276,607	-81,999
Rest of WECC Remote* CO2	35,840	32,996	-2,844
WECC			
CA (includes remote* and Imports)	83,547	85,545	1,999
Rest of WECC (includes remote*)	394,447	309,604	-84,843
Total WECC	477,994	395,149	-82,845

CHAPTER 8: ASSESSMENT OF UNCERTAINTIES

This chapter reports on the evaluation of each thematic scenario using a limited set of uncertainties. Section 8.1 examines the sensitivity and stochastic analyses that were undertaken to determine how sensitive the results were to changes from baseline assumptions to alternative ones. Three forms of sensitivity assessment were conducted:

- Full rerun of the production cost model for higher and lower than basecase natural gas prices;
- Rerun of the production cost for year 2020 alone examining the consequences of higher than normal hydro-electric generation, lower than normal hydro-electric generation; and super high natural gas prices averaging $20/MMBtu.
- A stochastic analysis of selected cases undertaken principally to determine whether there were reliability issues that might be uncovered with very different resource mixes in comparison to resource plans built out with conventional resources.

These sensitivity assessments are a small portion of the wide range of uncertainties that affect the results. Section 8.2 examines the variation in results when the aging power plant retirement policy adopted by the Energy Commission in the 2005 IEPR is considered. Finally, Section 8.3 summarizes an assessment of the impact of lower natural gas consumption for power generation, such as from high penetrations of energy efficiency and supply-side renewables on a West-wide basis, on natural gas market clearing prices. [Sections 8.2 and 8.3 are not included in this draft report since the analysis is not complete; they are forthcoming.]

8.1 Sensitivity to Alternative Fuel Price Projections

The reference case fuel price pattern used in all scenarios mirrors that developed by the Energy Information Administration in its *2007 Energy Outlook*. Using traditional relationships between Henry Hub and actual market points for natural gas deliveries, Global Energy developed specific natural gas price projections for the various market points corresponding to the topology for which the electricity production cost model was configured. Global Energy also developed two alternative fuel price trajectories—P25 and P75—that differ from the expected case using historic probability distributions of natural gas prices. These two alternative fuel price projections reflect lower and higher fuel prices relative to the reference case. The P25 case, or low case, is intended to reflect the probability that prices will be below this level only 25 percent of the time, while the P75 case, or high case, is interpreted as saying that prices will be below this level 75 percent of the time. Each of these alternatives was run in all cases to identify the variation in production dispatch among generating resources, as well as the aggregate cost implications of the departure from the expected fuel prices. Table 8-1 and Figure 8-1 show the base, high and low natural gas prices. Details of the methodology to produce these fuel price trajectories are provided in Section 5.6.

Table 8-2 shows the production and system cost results in 2006 dollars per MWh of the P75 and P25 sensitivities across each scenario. Figures 8-2 through 8-9 depict the results graphically for each of the scenarios. Table 8-3 reports the differences between the basecase and the P75 and P25 sensitivity for 2020. In the High Gas sensitivity for Case 1B – Current Requirements, system costs increase 11 percent more than the basecase, and production costs increase 16 percent more than the basecase. At the other spectrum, in Case 5B with high levels of energy efficiency and renewables in California and the Rest-of-WECC, system costs increase 6 percent in the High Gas sensitivity, and production costs increase 13 percent more than the basecase. In the Low Gas sensitivity for Case 1B, system costs decline 32 percent, and production costs decline 28 percent more than the basecase. In Case 5B, system costs decline by 11 percent and production costs decline by 23 percent. The results reveal that Case 1, with more natural gas-fired generation installed in its long-term resource plan, is more sensitive to natural gas price changes than the other cases with more preferred resources installed. As more preferred resources are added (i.e., either energy efficiency or renewables or both), total system costs increase, but the resource mix with more preferred resources is less sensitive to upswings in natural gas prices.

Table 8-1: Natural Gas Price Forecasts ($2006/MMBtu)

Year	Base Case P50	Base Case P75	P75 Difference	P75 % Difference	Base Case P25	P25 Difference	P25 % Difference
2009	7.17	8.66	1.49	21%	5.36	-1.81	-25%
2010	5.82	7.42	1.60	28%	4.29	-1.53	-26%
2011	5.36	6.47	1.11	21%	3.66	-1.70	-32%
2012	5.34	6.48	1.14	21%	3.61	-1.73	-32%
2013	5.61	6.98	1.37	24%	3.63	-1.98	-35%
2014	6.09	7.56	1.47	24%	3.85	-2.24	-37%
2015	5.99	7.35	1.36	23%	3.81	-2.18	-36%
2016	5.60	6.99	1.39	25%	3.45	-2.15	-38%
2017	5.83	7.24	1.41	24%	3.56	-2.27	-39%
2018	6.02	7.54	1.52	25%	3.57	-2.45	-41%
2019	6.36	7.91	1.55	24%	3.79	-2.57	-40%
2020	6.96	8.60	1.64	24%	4.12	-2.84	-41%

Source: Global Energy

Figure 8-1: Natural Gas Price Forecasts ($2006/MMBtu)

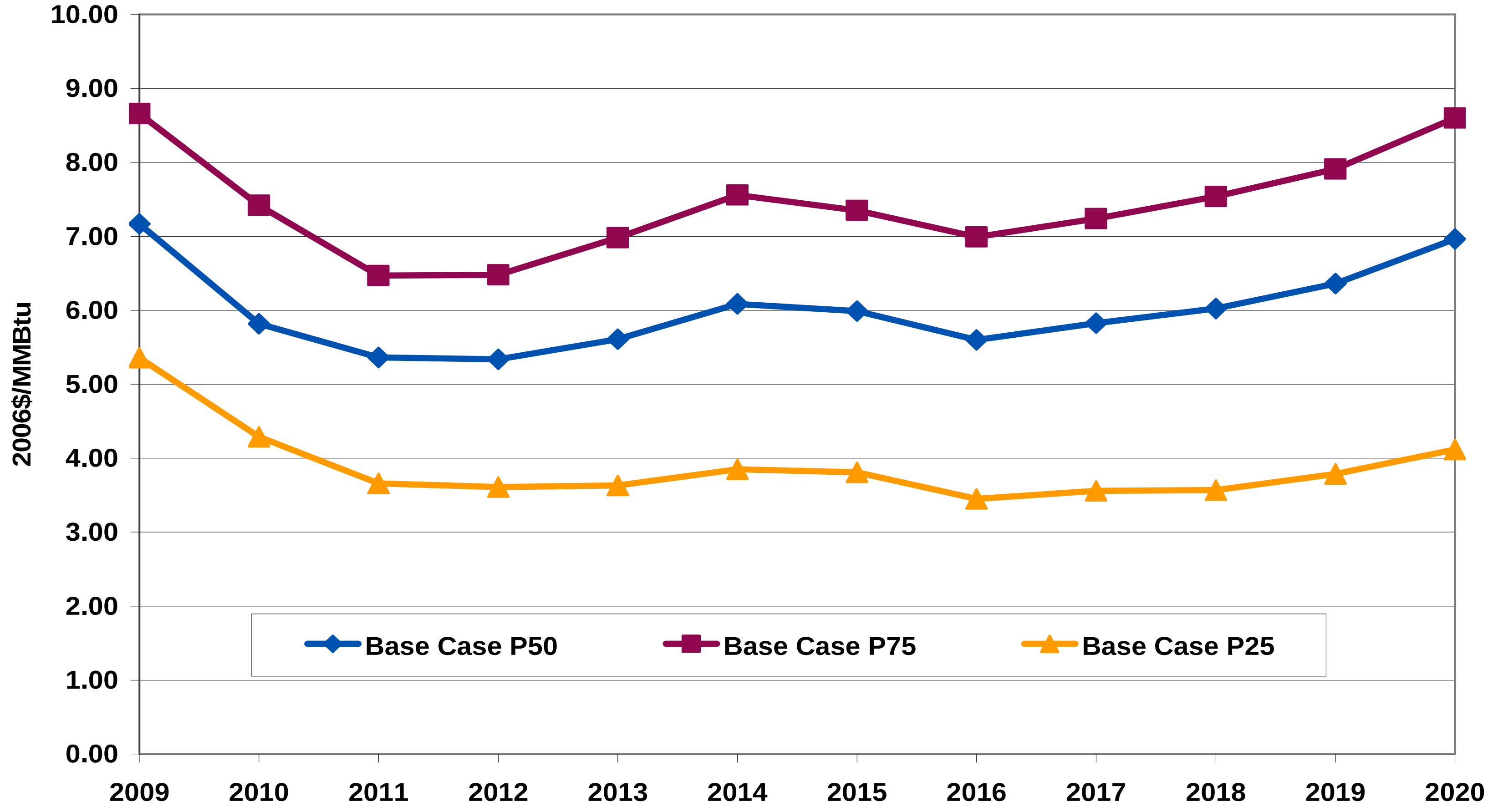


Table 8-2: System and Production Cost Results Basecase, P75, and P25 Sensitivities ($2006/MWh)

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Case 1													
System	Base NG	43.33	39.29	36.86	37.53	38.64	41.21	41.47	40.29	41.13	43.34	45.28	49.00
	High NG	48.81	44.68	41.38	42.45	44.54	47.49	47.26	46.47	47.31	50.09	52.19	56.33
	Low NG	35.25	31.60	29.79	29.97	30.04	31.54	31.96	30.66	31.19	32.22	33.64	36.03
Production	Base NG	42.66	38.31	35.80	36.39	37.42	39.45	39.00	37.32	37.75	39.15	40.64	43.34
	High NG	48.14	43.70	40.32	41.31	43.31	45.73	44.79	43.50	43.93	45.89	47.55	50.66
	Low NG	34.58	30.62	28.73	28.83	28.82	29.78	29.48	27.69	27.81	28.03	28.99	30.36
Case 1B													
System	Base NG	47.44	43.32	40.88	43.50	45.89	48.28	48.16	47.07	47.44	49.01	50.49	53.00
	High NG	52.67	48.57	45.25	48.01	51.05	53.74	53.14	52.34	52.62	54.73	56.32	59.06
	Low NG	35.25	31.60	29.79	29.97	30.04	31.54	31.96	30.66	31.19	32.22	33.64	36.03
Production	Base NG	41.97	37.47	34.89	34.52	34.51	35.93	35.45	33.87	34.08	35.26	36.39	38.55
	High NG	47.21	42.72	39.26	39.04	39.67	41.40	40.42	39.15	39.26	40.97	42.21	44.61
	Low NG	34.00	29.94	28.07	27.58	26.90	27.54	27.22	25.58	25.62	25.84	26.56	27.70
Case 3A													
System	Base NG	47.69	43.68	41.59	43.79	46.12	48.41	48.40	47.35	47.72	49.27	50.69	53.10
	High NG	52.96	48.92	45.88	48.26	51.20	53.70	53.25	52.50	52.74	54.79	56.30	58.96
	Low NG	39.71	36.19	34.80	36.91	38.62	40.18	40.35	39.26	39.49	40.14	41.23	42.67
Production	Base NG	41.93	37.37	34.75	34.30	34.18	35.50	34.93	33.31	33.40	34.44	35.43	37.43
	High NG	47.20	42.61	39.05	38.77	39.26	40.79	39.77	38.46	38.42	39.96	41.05	43.29
	Low NG	33.95	29.88	27.97	27.42	26.68	27.26	26.88	25.22	25.17	25.32	25.98	27.00
Case 3B													
System	Base NG	47.54	43.51	41.43	43.60	45.88	48.11	48.06	47.08	47.39	48.96	50.33	52.68
	High NG	52.80	48.67	45.63	47.98	50.83	53.32	52.80	52.06	52.26	54.27	55.80	58.36
	Low NG	39.64	36.11	34.72	36.80	38.49	40.04	40.18	39.15	39.34	40.02	41.07	42.51
Production	Base NG	41.78	37.20	34.59	34.11	33.94	35.21	34.60	33.05	33.09	34.14	35.09	37.02
	High NG	47.04	42.36	38.80	38.49	38.89	40.42	39.35	38.04	37.96	39.46	40.56	42.70
	Low NG	33.87	29.80	27.89	27.31	26.55	27.14	26.73	25.13	25.05	25.20	25.83	26.85
Case 4A													

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
System	Base NG	47.86	43.88	42.85	46.69	49.75	53.61	55.09	55.55	56.58	58.49	60.26	62.68
	High NG	53.13	49.14	47.15	51.17	54.85	58.85	59.70	60.25	61.00	63.18	64.82	67.26
	Low NG	39.90	36.37	36.04	39.75	42.17	45.49	47.43	48.08	49.30	50.67	52.48	54.46
Production	Base NG	41.94	37.44	34.85	34.57	34.66	35.46	34.23	32.11	31.54	31.87	31.99	32.83
	High NG	47.21	42.69	39.15	39.05	39.76	40.69	38.84	36.81	35.95	36.56	36.55	37.41
	Low NG	33.98	29.92	28.04	27.62	27.09	27.33	26.57	24.64	24.26	24.05	24.21	24.61
Case 4B													
System	Base NG	47.87	43.87	42.84	46.64	49.68	53.49	54.94	55.38	56.42	58.31	60.08	62.58
	High NG	53.14	49.14	47.18	51.11	54.79	58.68	59.50	60.02	60.77	62.94	64.62	67.11
	Low NG	39.87	36.38	36.05	39.72	42.12	45.45	47.36	48.01	49.23	50.60	52.42	54.43
Production	Base NG	41.95	37.43	34.84	34.52	34.59	35.33	34.08	31.94	31.37	31.69	31.81	32.73
	High NG	47.22	42.70	39.18	38.99	39.71	40.52	38.63	36.58	35.72	36.32	36.35	37.26
	Low NG	33.95	29.93	28.05	27.59	27.04	27.29	26.49	24.57	24.19	23.98	24.16	24.58
Case 5A													
System	Base NG	48.09	44.26	43.57	47.00	50.07	53.96	55.71	56.37	57.45	59.45	61.20	63.64
	High NG	53.41	49.50	47.84	51.42	55.10	59.07	60.18	60.95	61.68	63.92	65.50	67.89
	Low NG	40.16	36.80	36.81	40.14	42.58	46.00	48.24	49.15	50.48	51.98	53.86	55.95
Production	Base NG	41.88	37.35	34.70	34.32	34.35	35.00	33.67	31.47	30.75	30.96	30.88	31.54
	High NG	47.19	42.59	38.97	38.74	39.39	40.11	38.15	36.05	34.98	35.43	35.18	35.79
	Low NG	33.95	29.88	27.94	27.46	26.87	27.04	26.21	24.24	23.78	23.49	23.54	23.85
Case 5B													
System	Base NG	47.96	44.06	43.39	46.72	49.58	53.35	55.07	55.76	56.81	58.78	60.68	63.06
	High NG	53.20	49.26	47.58	51.08	54.39	58.18	59.28	60.01	60.73	62.90	64.65	66.97
	Low NG	40.08	36.70	36.72	40.02	42.35	45.73	47.97	48.91	50.27	51.77	53.71	55.82
Production	Base NG	41.74	37.15	34.52	34.04	33.87	34.38	33.03	30.86	30.10	30.29	30.35	30.96
	High NG	46.99	42.35	38.72	38.39	38.68	39.22	37.24	35.11	34.02	34.42	34.32	34.87
	Low NG	33.86	29.79	27.85	27.34	26.64	26.77	25.93	24.01	23.56	23.28	23.39	23.72

Figure 8-2: System and Production Unit Cost Trends for Case 1 – Current Conditions (High and Low Natural Gas Price Projections)

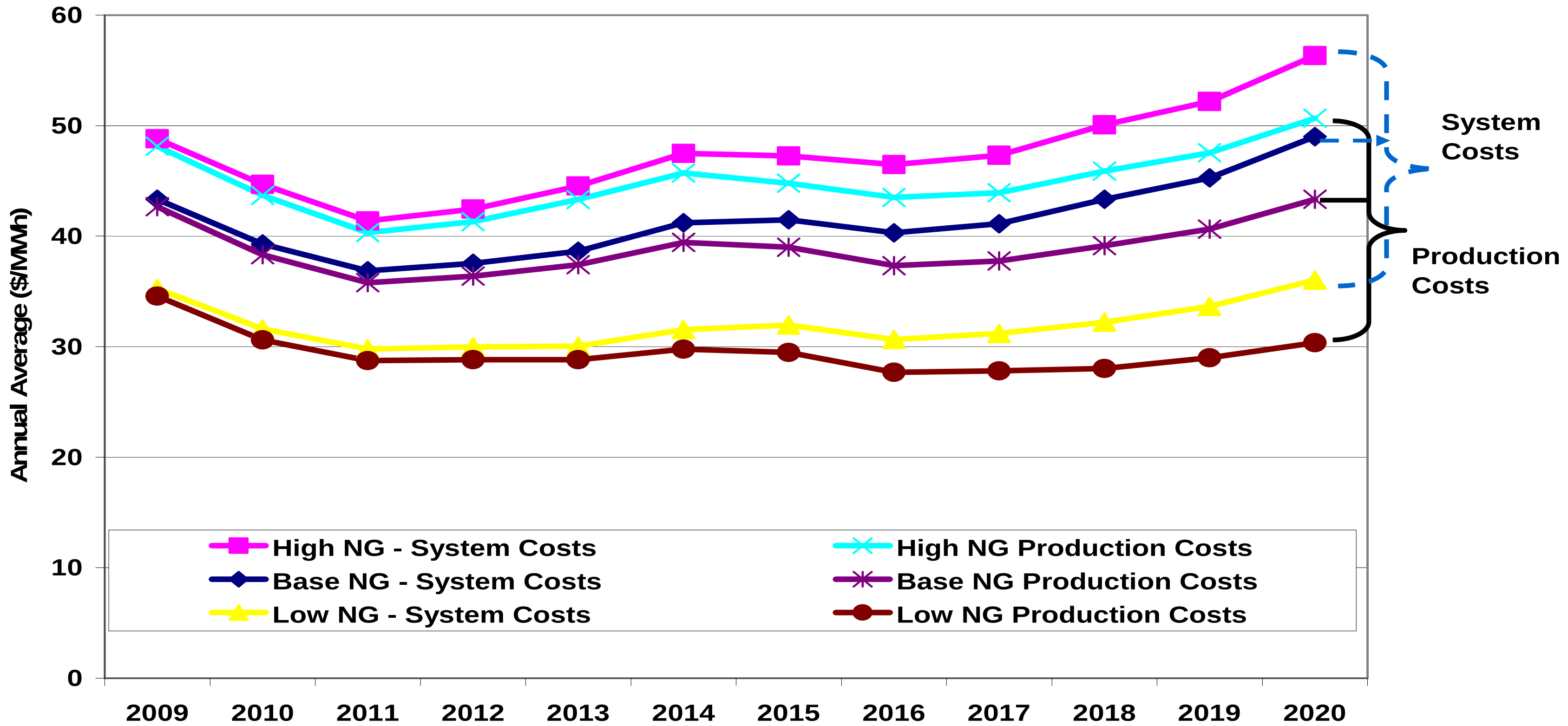


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Figure 8-3: System and Production Unit Cost Trends for Case 1B – Current Requirements (High and Low Natural Gas Price Projections)

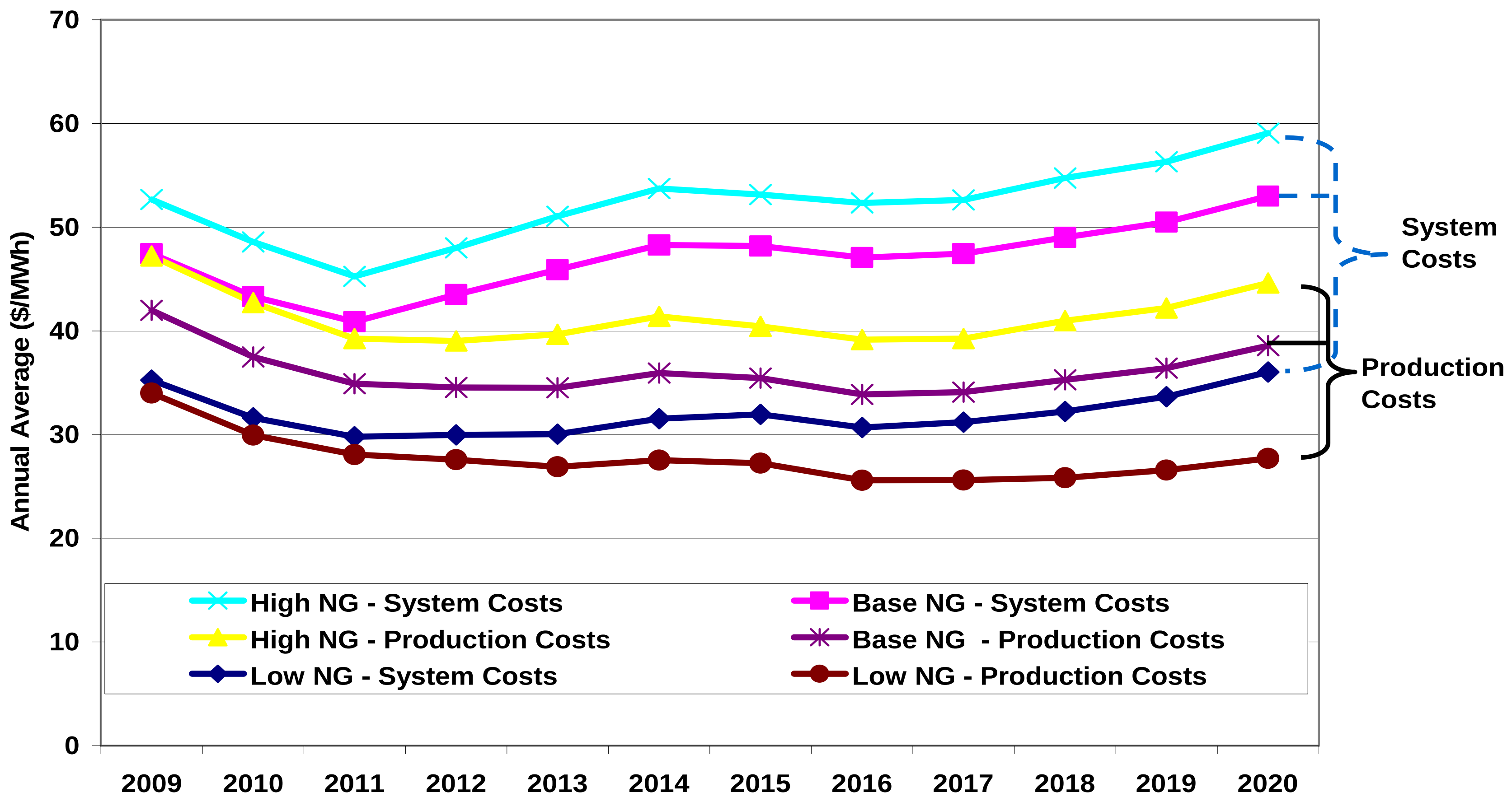


Figure 8-4: System and Production Unit Cost Trends for Case 3A – High Energy Efficiency in California Only (High and Low Natural Gas Price Projections)

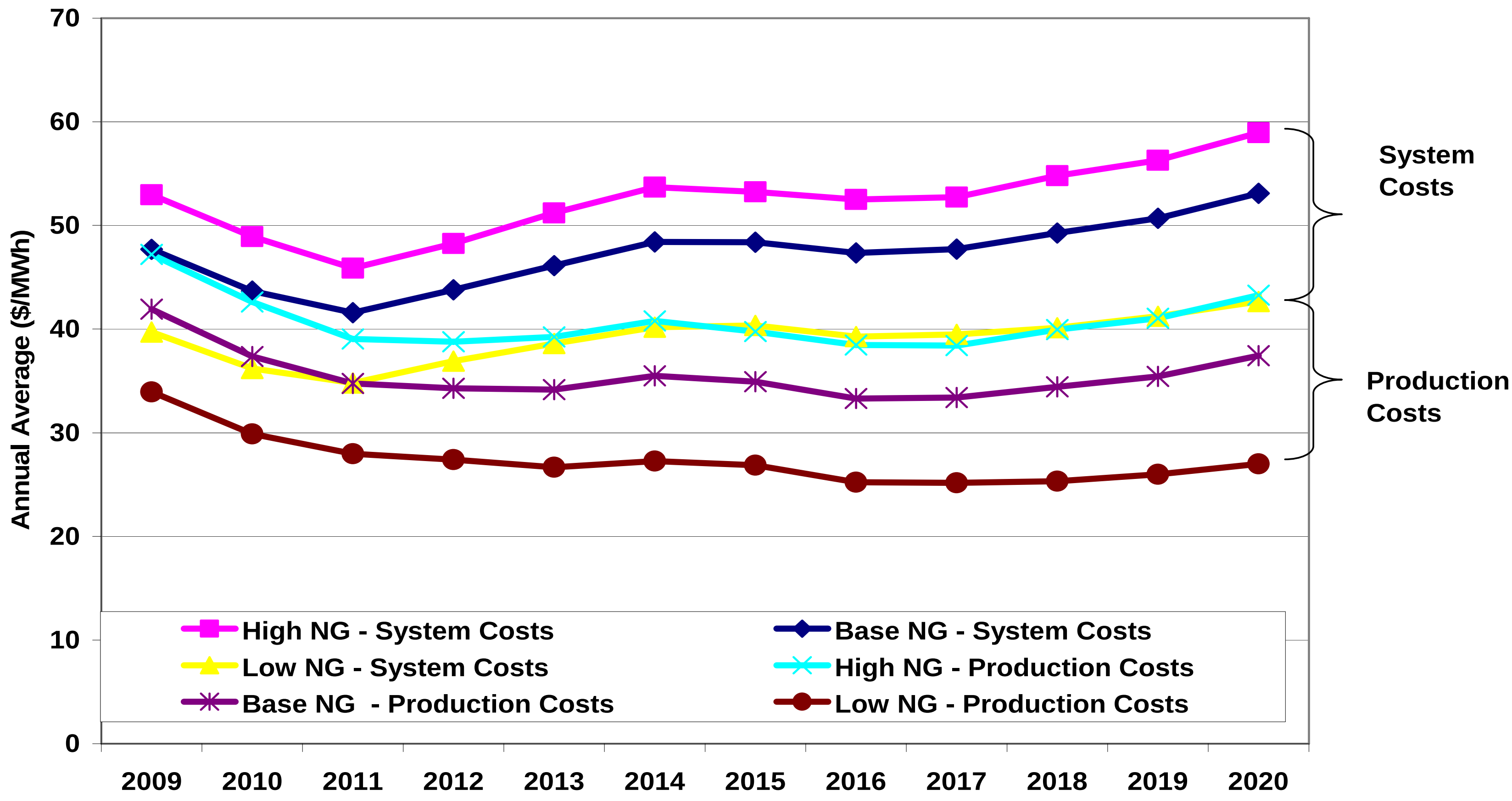


Figure 8.5: Case 3B – High Energy Efficiency in California and Rest-of-WECC System and Production Unit Cost Trends High and Low Natural Gas Price Projections

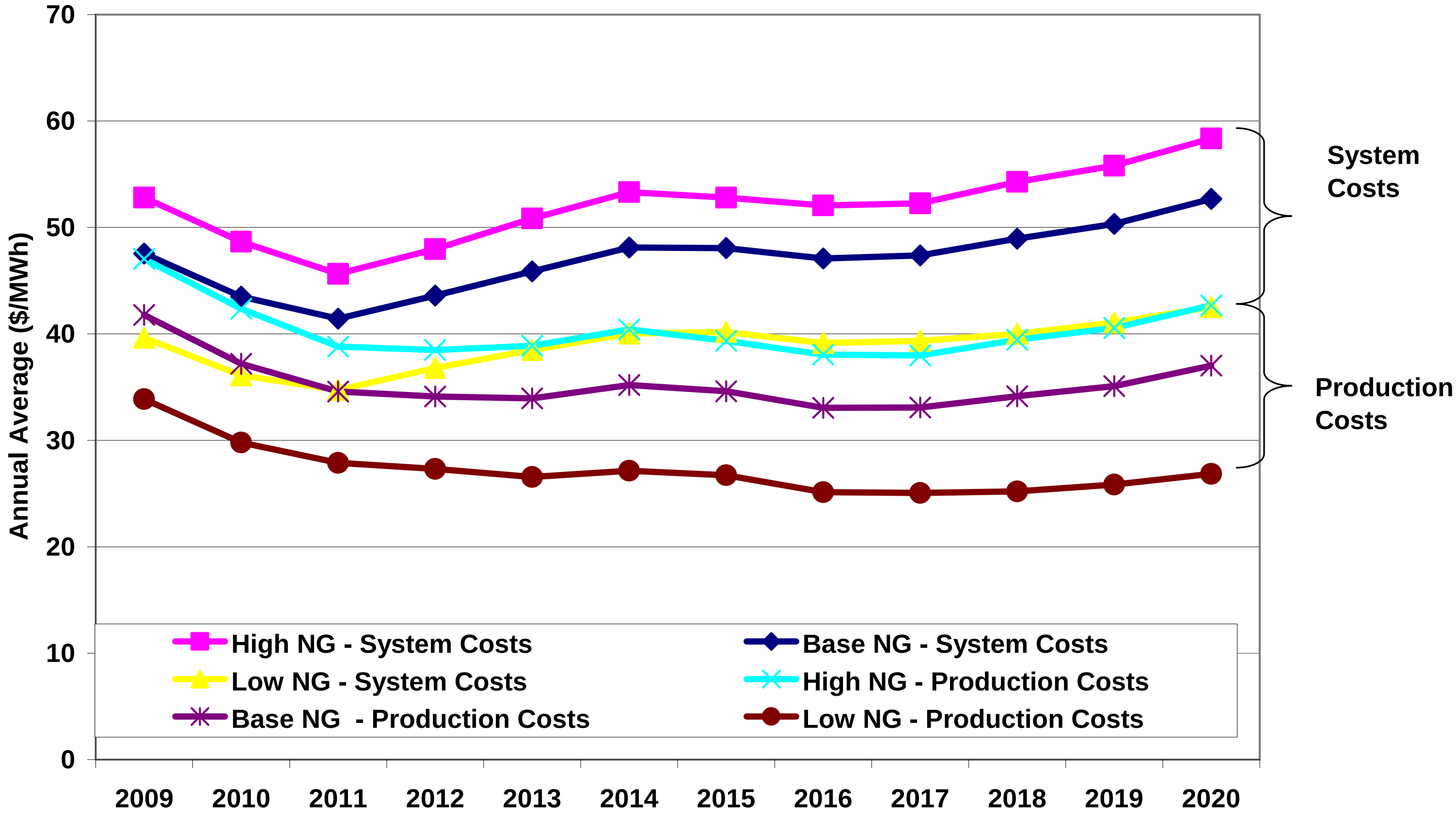


Figure 8-6: System and Production Unit Cost Trends for Case 4A – High Renewables in California Only (High and Low Natural Gas Price Projections)

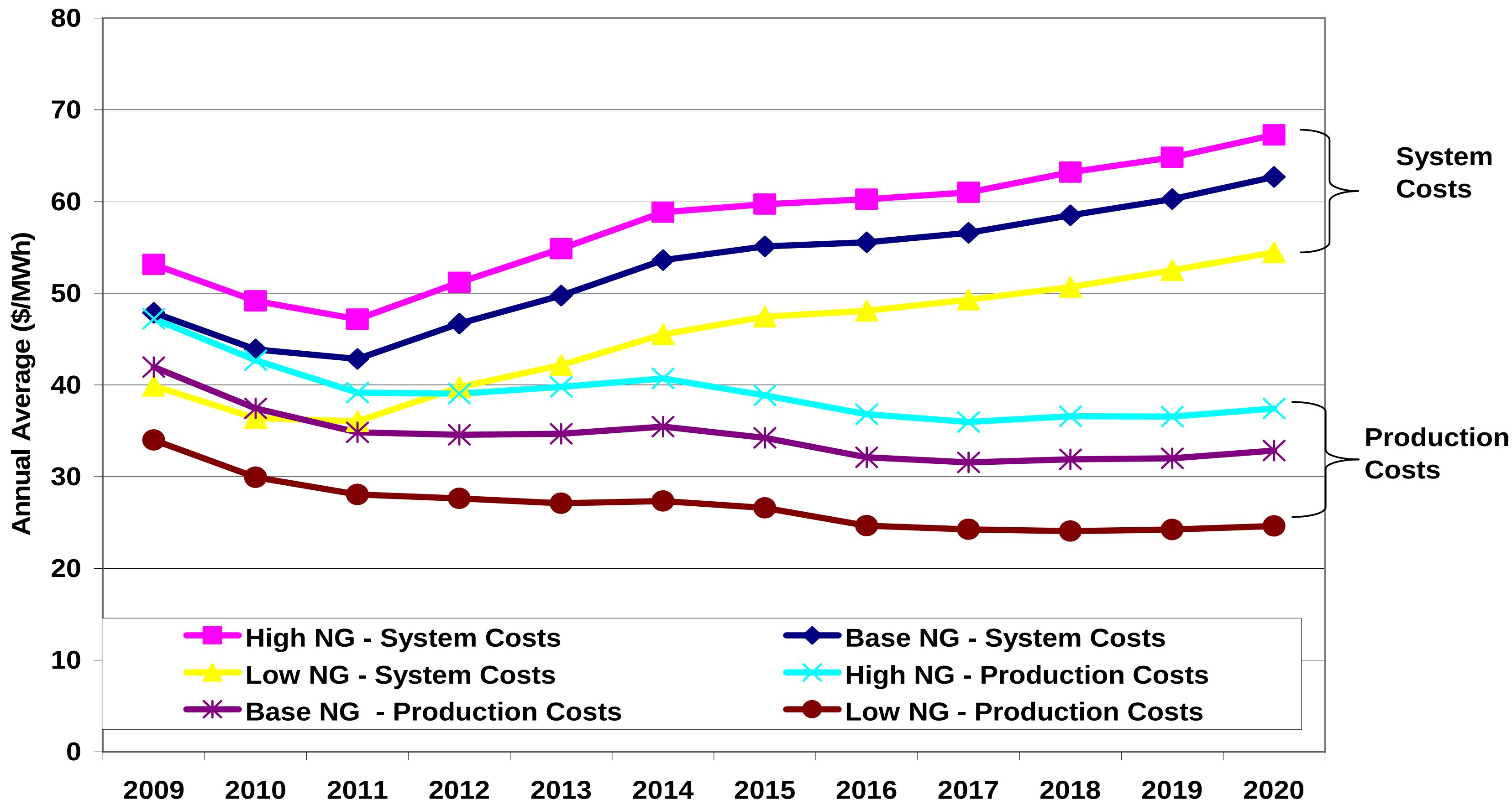


Figure 8-7: Case System and Production Unit Cost Trends for 4B – High Renewables in California and Rest-of-WECC (High and Low Natural Gas Price Projections)

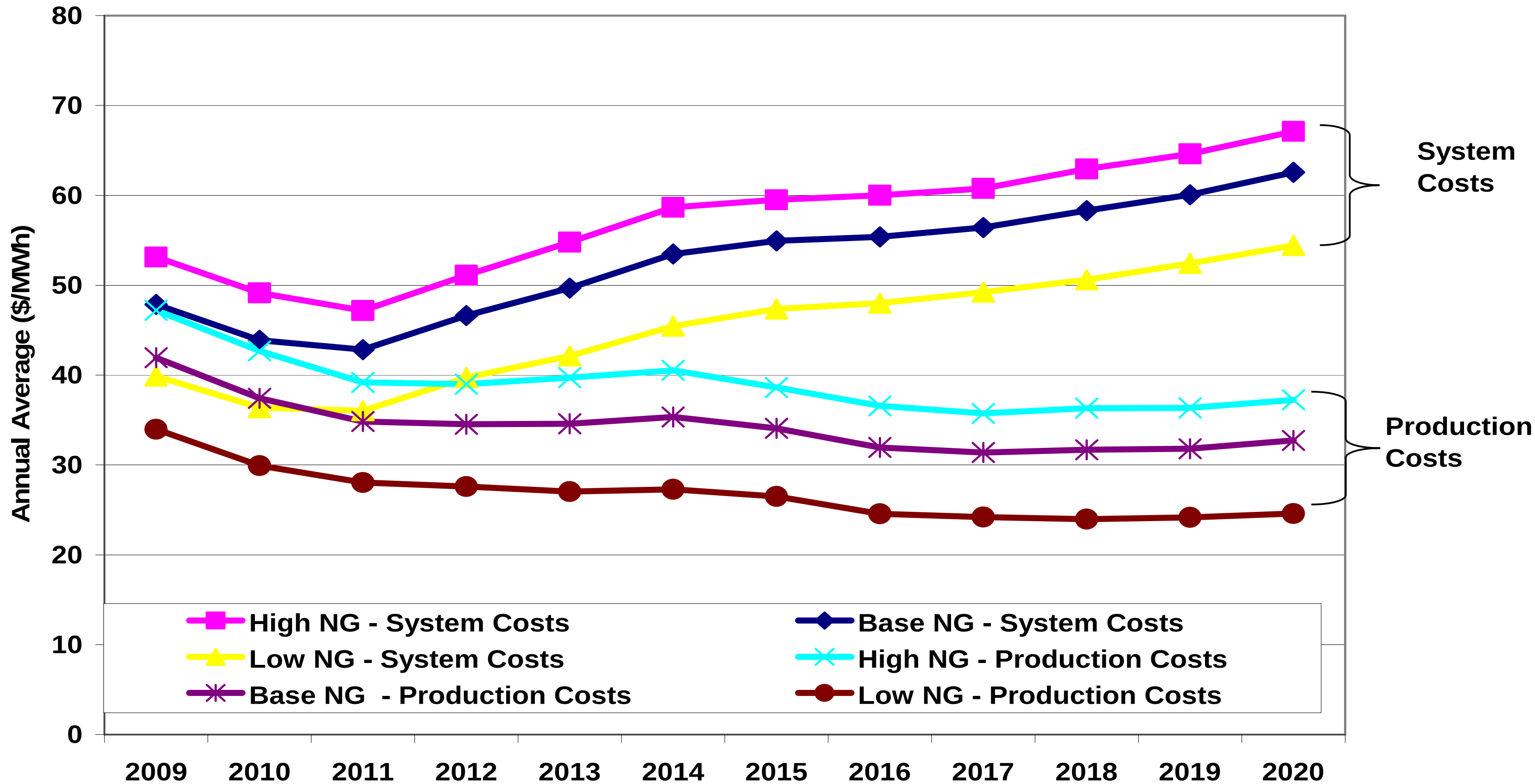


Figure 8-8: System and Production Unit Cost Trends for Case 5A – High Energy Efficiency and Renewables in California Only (High and Low Natural Gas Price Projections)

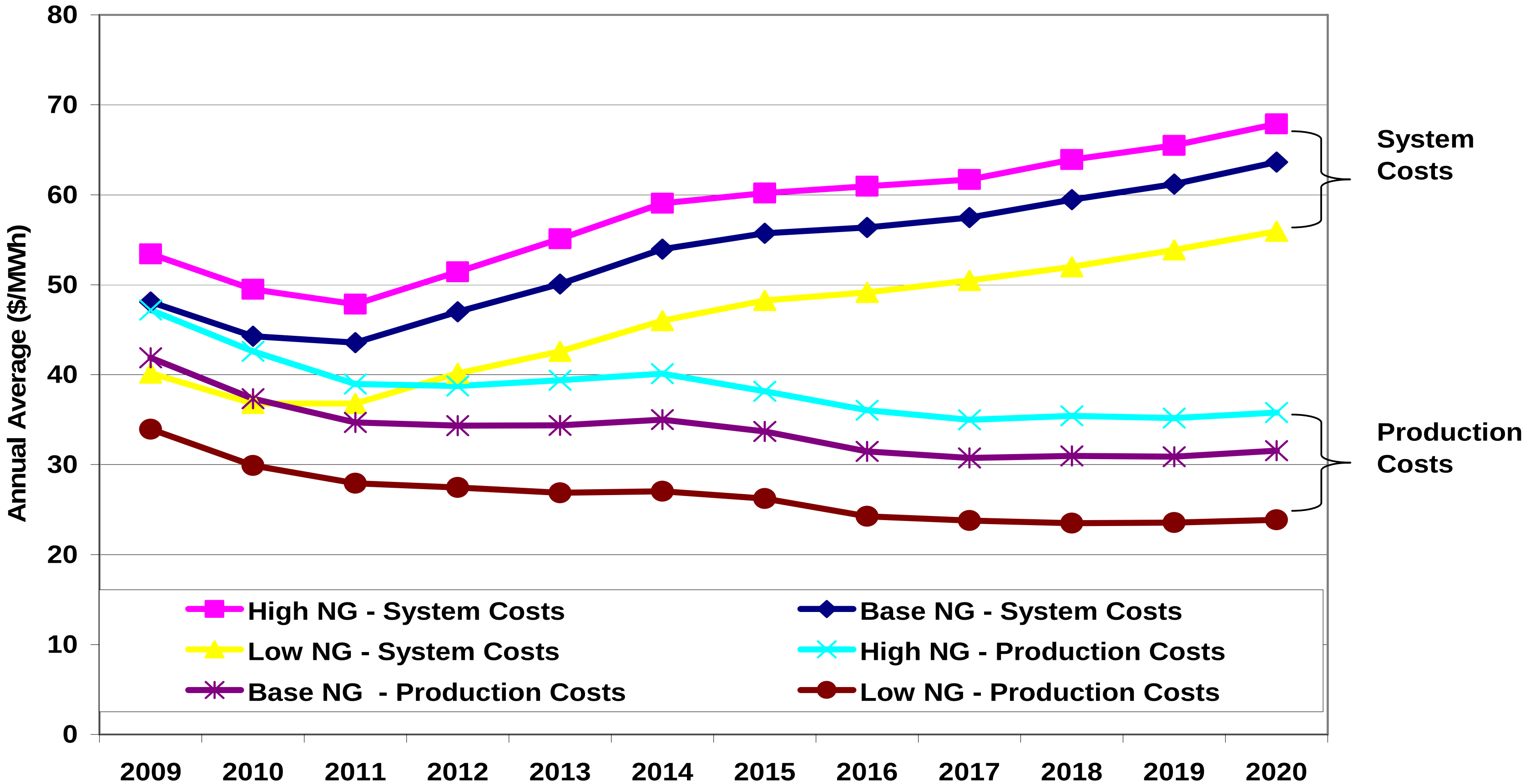


Figure 8-9: System and Production Unit Cost Trends for Case 5B – High Energy Efficiency and Renewables in California and Rest-of-WECC (High and Low Natural G as Price Projections)

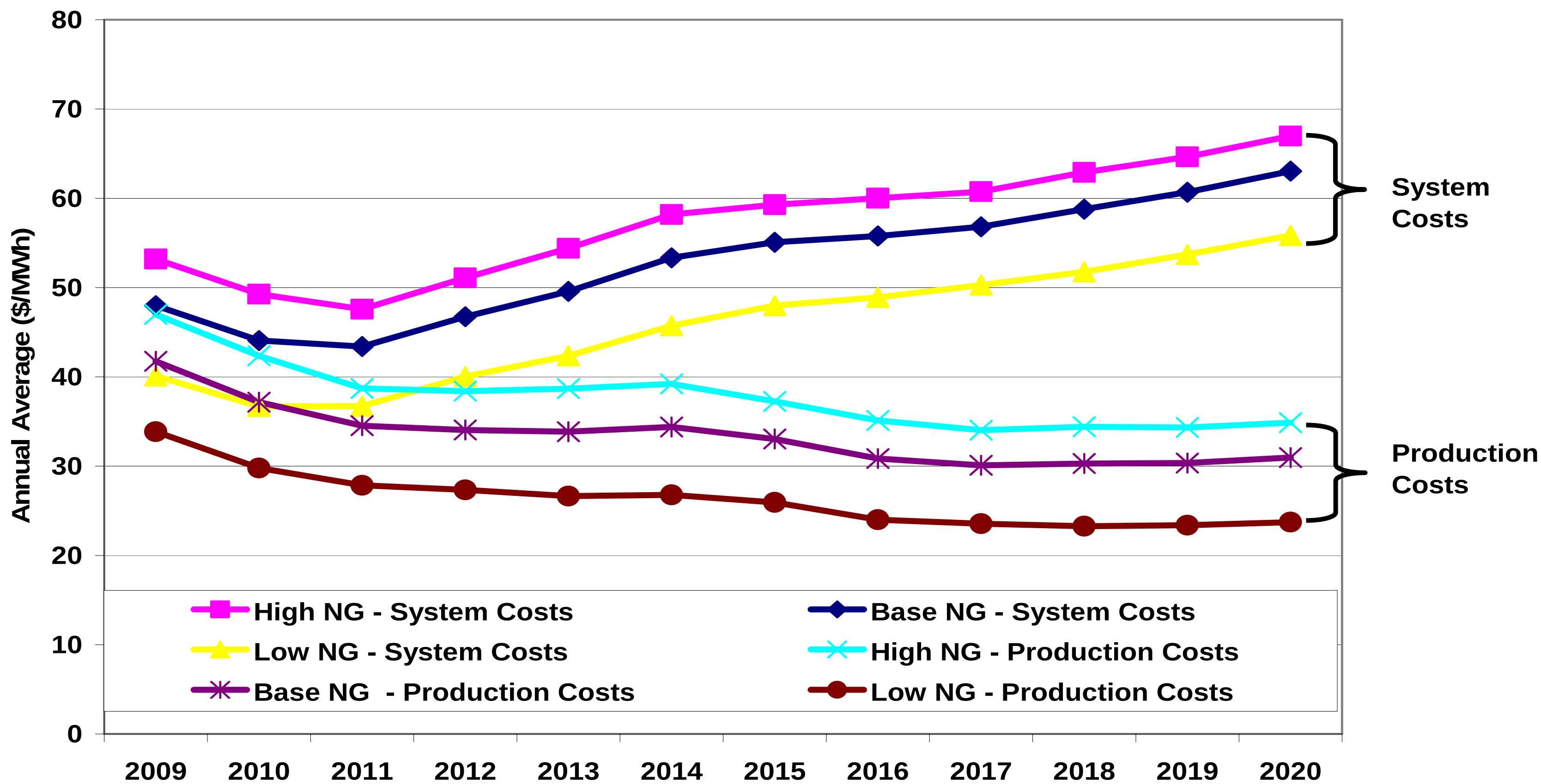


Table 8-3: Comparison of System and Unit Cost Trends Across the Scenarios for 2020

	System Costs					Production Costs				
	Base	High	% Difference	Low	% Difference	Base	High	% Difference	Low	% Difference
Case 1	49.00	56.33	15%	36.03	-26%	43.34	50.66	17%	30.36	-30%
Case 1B	53.00	59.06	11%	36.03	-32%	38.55	44.61	16%	27.70	-28%
Case 3A	53.10	58.96	11%	42.67	-20%	37.43	43.29	16%	27.00	-28%
Case 3B	52.68	58.36	11%	42.51	-19%	37.02	42.70	15%	26.85	-27%
Case 4A	62.68	67.26	7%	54.46	-13%	32.83	37.41	14%	24.61	-25%
Case 4B	62.58	67.11	7%	54.43	-13%	32.73	37.26	14%	24.58	-25%
Case 5A	63.64	67.89	7%	55.95	-12%	31.54	35.79	13%	23.85	-24%
Case 5B	63.06	66.97	6%	55.82	-11%	30.96	34.87	13%	23.72	-23%

8.2 Exogenous Shocks

Three sensitivity cases reflecting "shocks" were developed and quantified using PROSYM. The concept of a "shock" is that it is an uncertainty affecting system performance that the resource mix must be capable of overcoming while still providing desired levels of reliability. It is transitory and not permanent; thus, the resource plan cannot be optimized as though this were a regular event. Each "shock" was designed to last one year, and then the affected variables returned to nominal values. The variables modified were:

- Natural gas prices averaging $20/mmbtu reflecting a hurricane Katrina-type removal of major production capacity requiring one year to replace;
- High hydro generation across all major hydro-electric generation regions; and
- Low hydro generation across all major hydro-electric generation regions.

Table 8-4 shows the hydro energy assumed in the high hydro and low hydro cases. In a normal hydro year in Case 1, hydro energy accounts for about 22 percent of WECC-wide energy needs in 2020. In the dry hydro sensitivity, it drops to about 19 percent and in the high hydro, it increases to about 27 percent of WECC-wide energy needs in 2020. Figures 8-11 through Figure 8-19 show the mix of energy generated across the various scenarios under the shocks to hydro and natural gas prices. In the low and high hydro sensitivities across all of the cases, the California system largely responds by dispatching more and less natural gas-fired resources, respectively. In the average $20/MMBtu natural gas price sensitivity across all of the cases, the system largely responds by displacing natural gas with fuel oil and variable demand response.

Table 8-4: WECC Hydro Energy for Low and High Hydro Case

Year	Hydro Condition	GWh
Average	Normal	246,167
1997	Wet	300,319
2000-2001	Dry	213,547

California average/normal hydro data is based on the average of 1990-2002.
Northwest average/normal hydro data is based on the average of 1990-2002.
British Columbia average/normal hydro data is based on reported levels by BC Hydro

Figure 8-20 shows a comparison of system costs between Case 1B – Current Conditions and Case 5A - High Energy Efficiency and High Renewables in California Only, and Figure 8-21 shows a comparison of production costs between these cases. Case 1B system costs for California are lower than Case 5A system costs, except Case 1B has higher system costs under extremely high $20 gas prices. In addition, the production costs in Case 5A are less sensitive to extremely high natural gas prices than the production costs in Case 1B, similar to the results seen in the low and high fuel sensitivity cases.

Figure 8-10 shows the shape of the average $20/MMBtu natural gas prices in 2020. This shape is the historic average monthly variation in prices applied to an annual average of $20/mmbtu. This shape makes some minor changes in power plant dispatch through the course of the year.

Figure 8-10: Natural Gas Prices Averaging $20/MMBtu

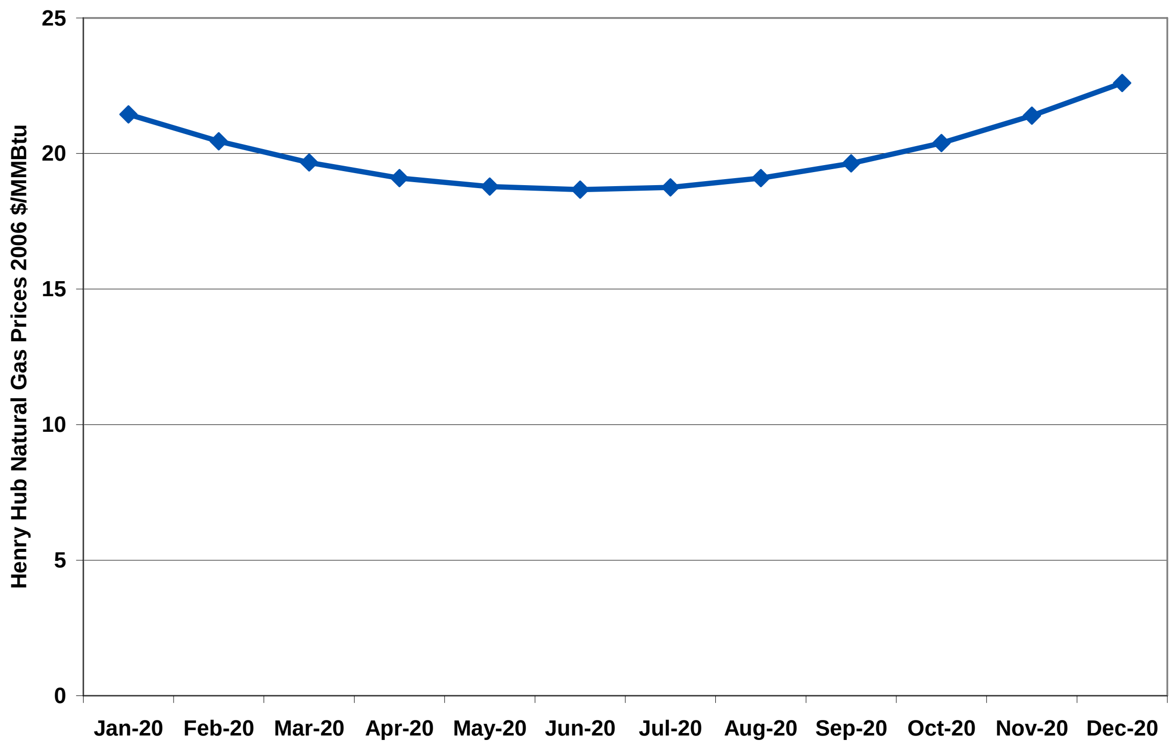


Figure 8-11: Annual California Generation by Resource Type in 2020 for Case 1 – Current Conditions Shock Sensitivity Results

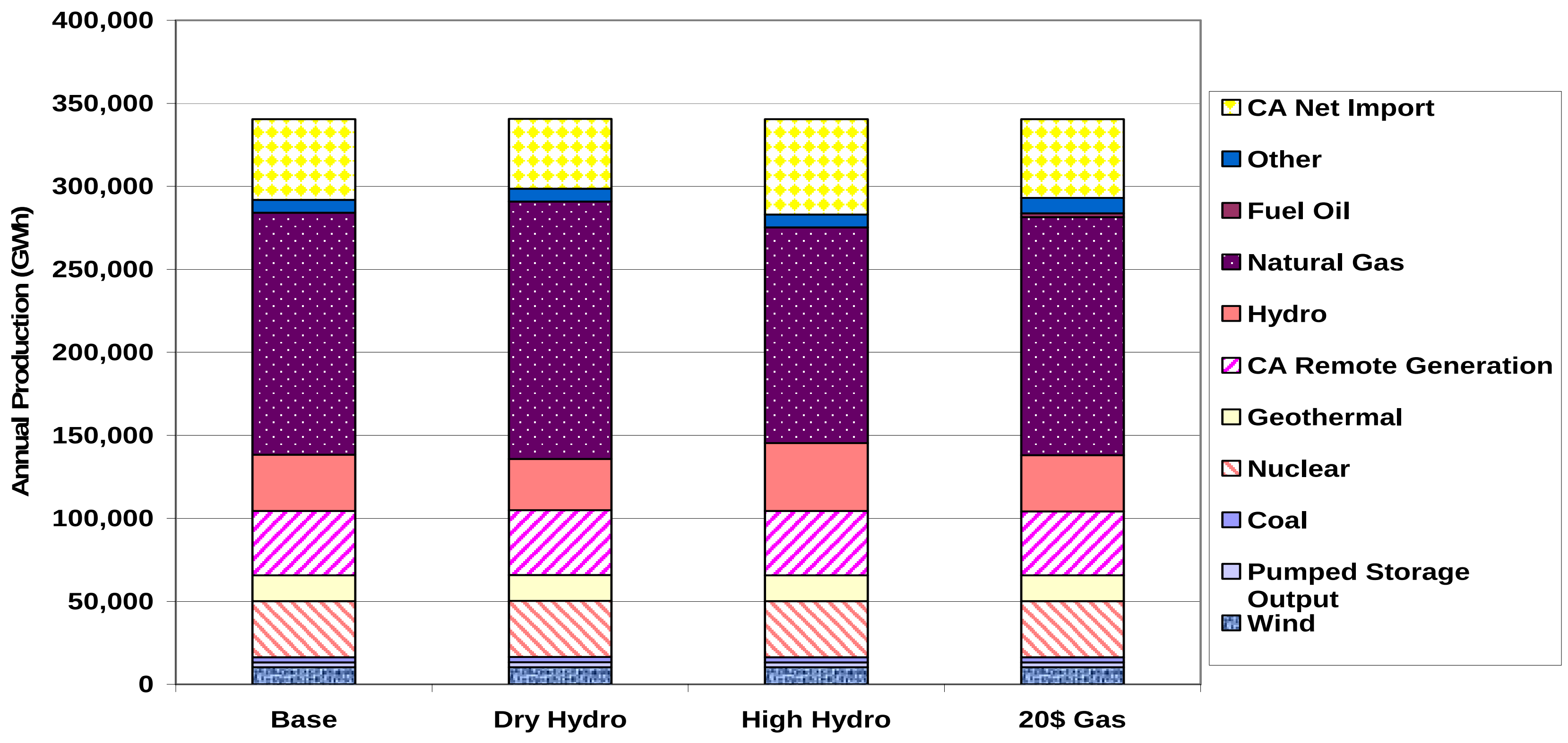


Figure 8-12: Annual California Generation by Resource Type in 2020 for Case 1B – Current Requirements Shock Sensitivity Results

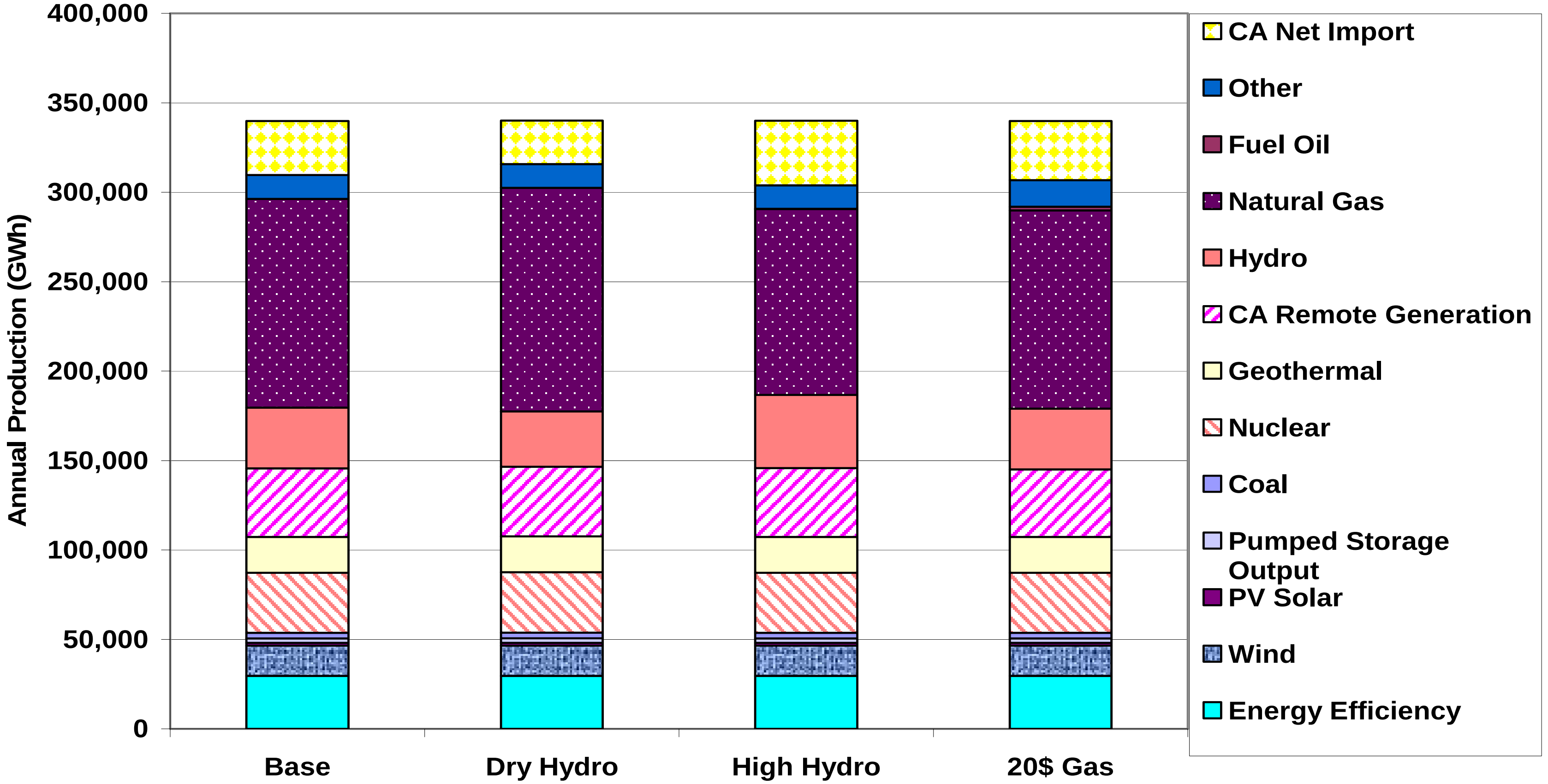


Figure 8-13: Annual California Generation by Resource Type in 2020 for Case 2 - Sustained High Gas and Coal Prices Shock Sensitivity Results

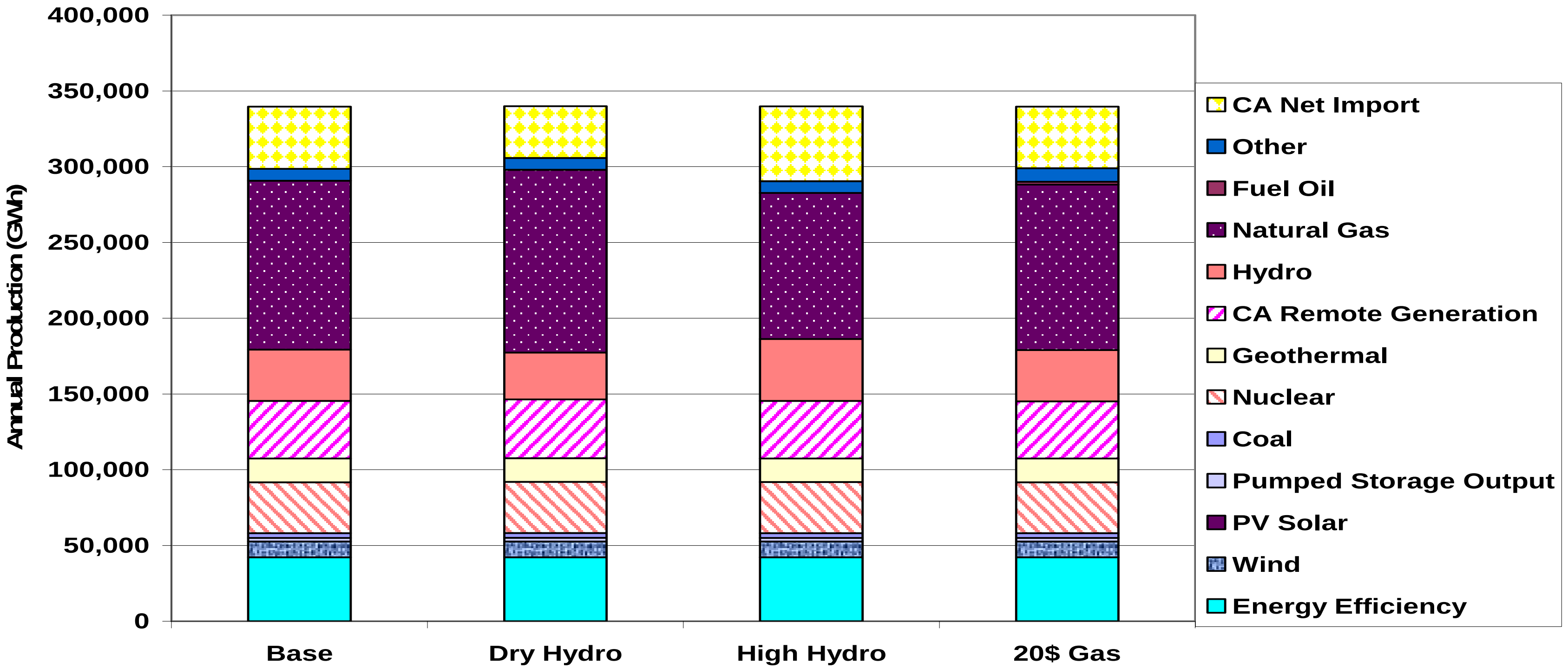


Figure 8-14: Annual California Generation by Resource Type in 2020 for Case 3A – High Energy Efficiency in California Only Shock Sensitivity Results

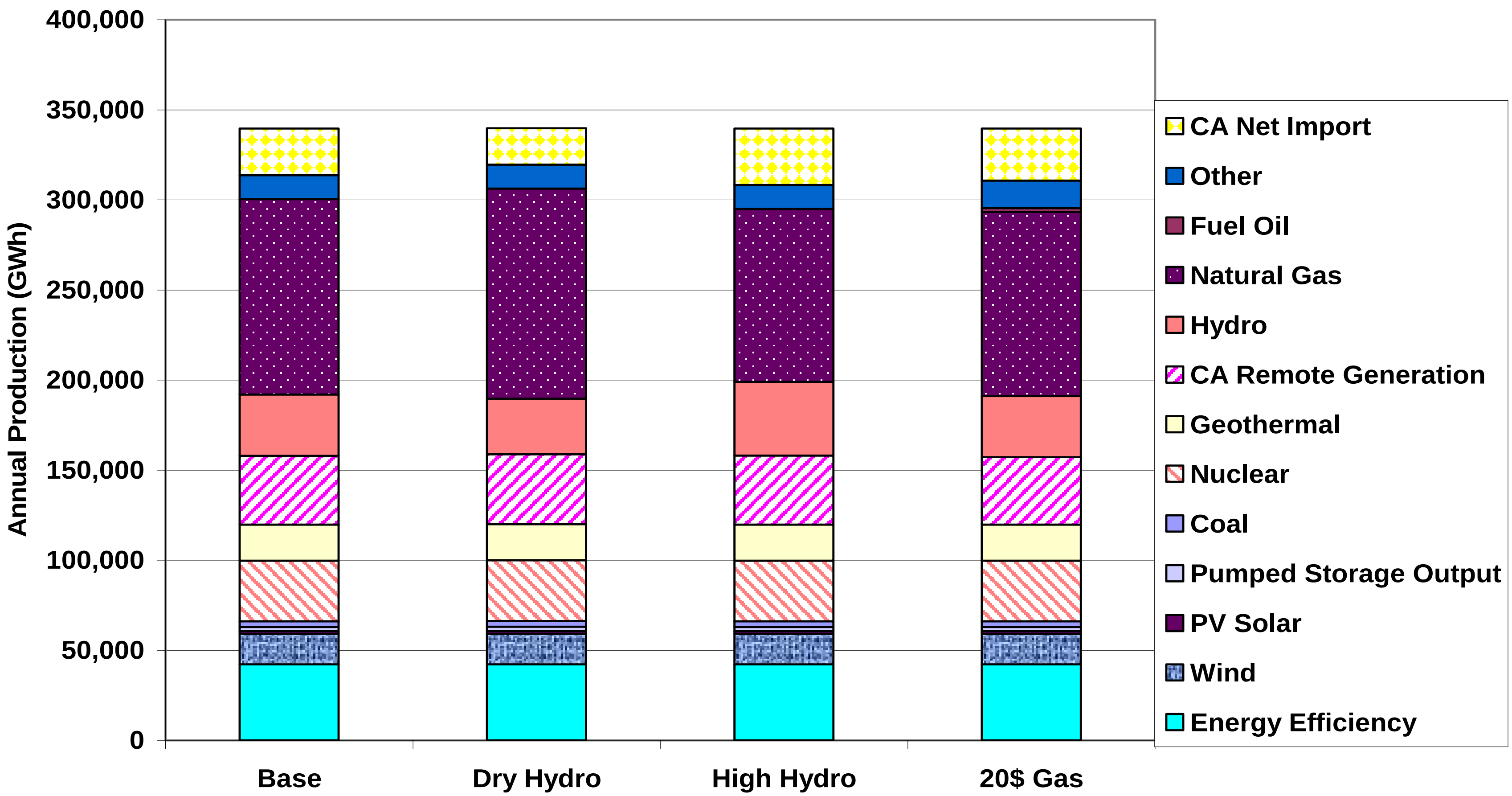


Figure 8-15 Annual California Generation by Resource Type in 2020 for Case 3B – High Energy Efficiency both in California and Rest-of-WECC Shock Sensitivity Results

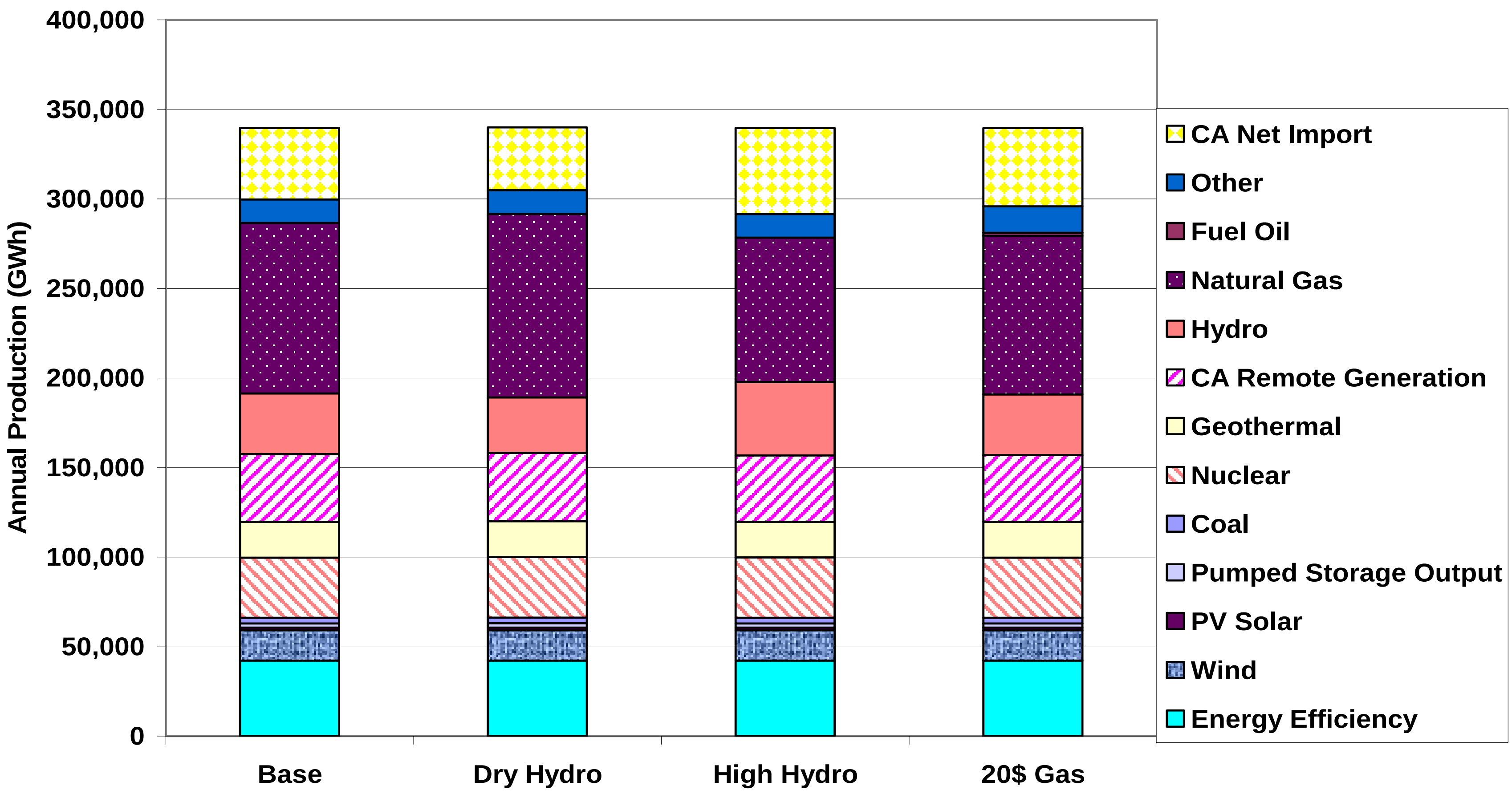


Figure 8.16: Annual California Generation by Resource Type in 2020 for Case 4A – High Renewables in California Only Shock Sensitivity Results

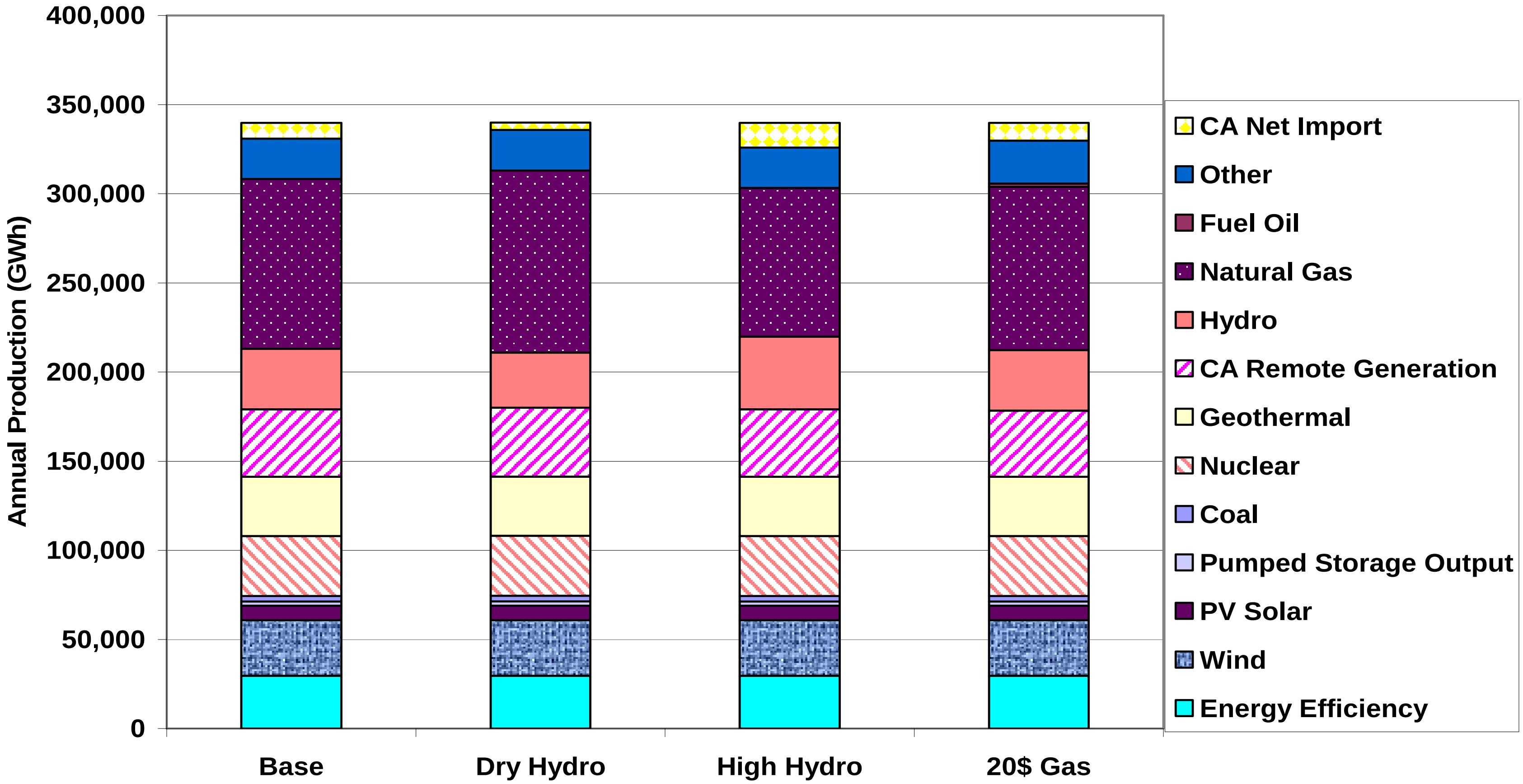


Figure 8-17: Annual California Generation by Resource Type in 2020 for Case 4B – High Renewables both in California and Rest-of-WECC Shock Sensitivity Results

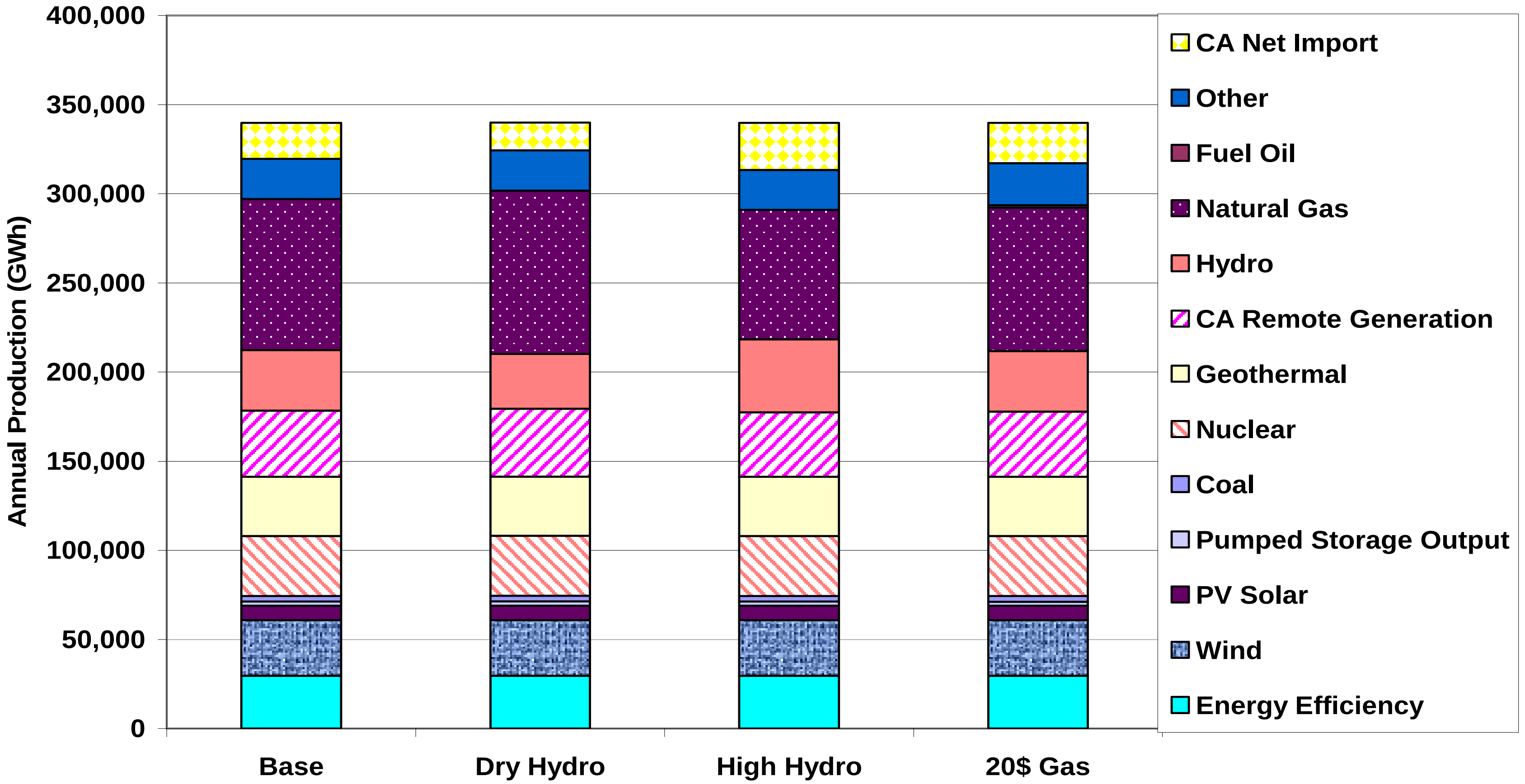


Figure 8-18: Annual California Generation by Resource Type in 2020 for Case 5A – High Energy Efficiency and Renewables in California Only Shock Sensitivity Results

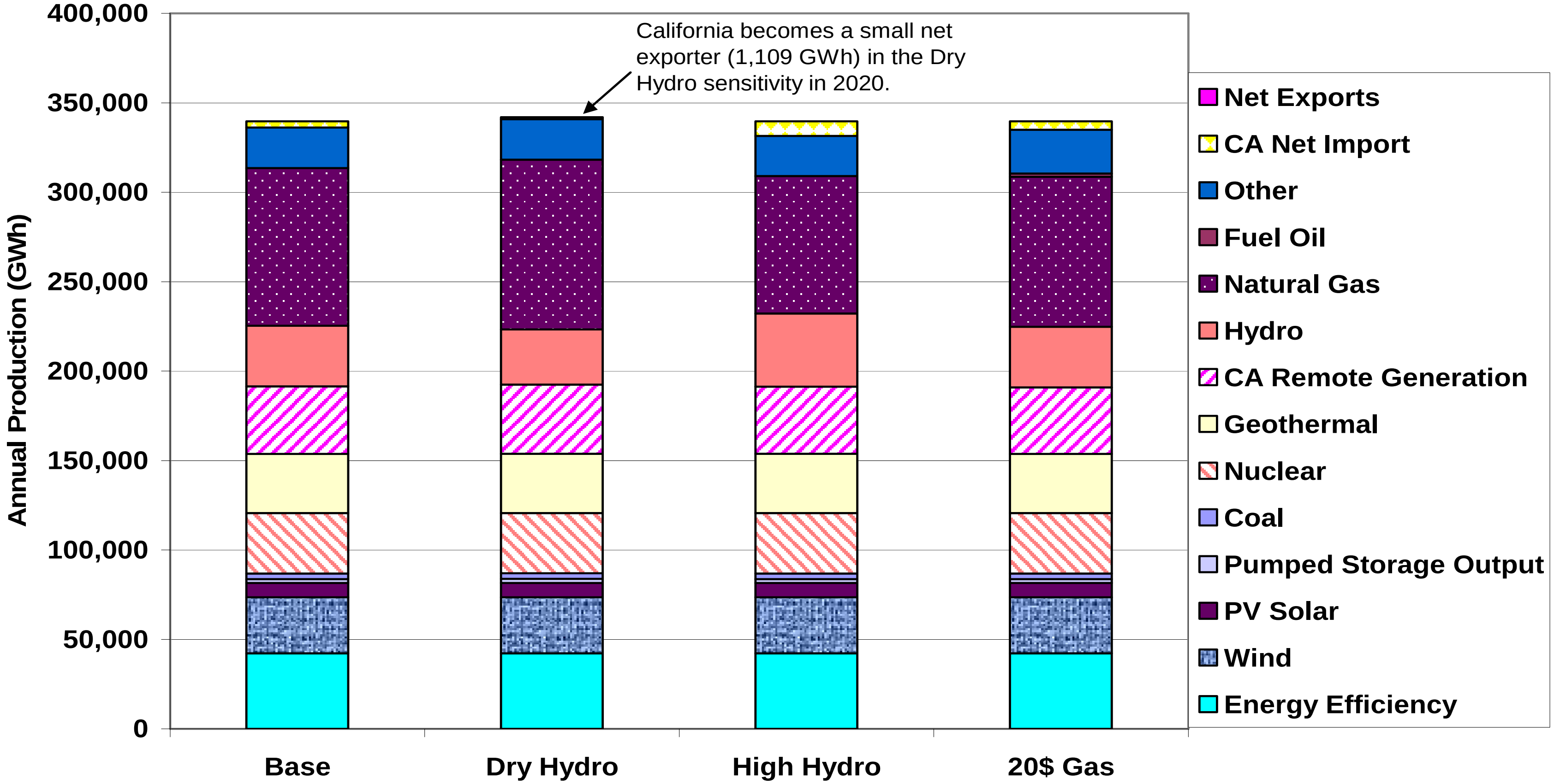


Figure 8-19: Annual California Generation by Resource Type in 2020 for Case 5B – High Energy Efficiency and Renewables Both in California and Rest-of-WECC Shock Sensitivity Results

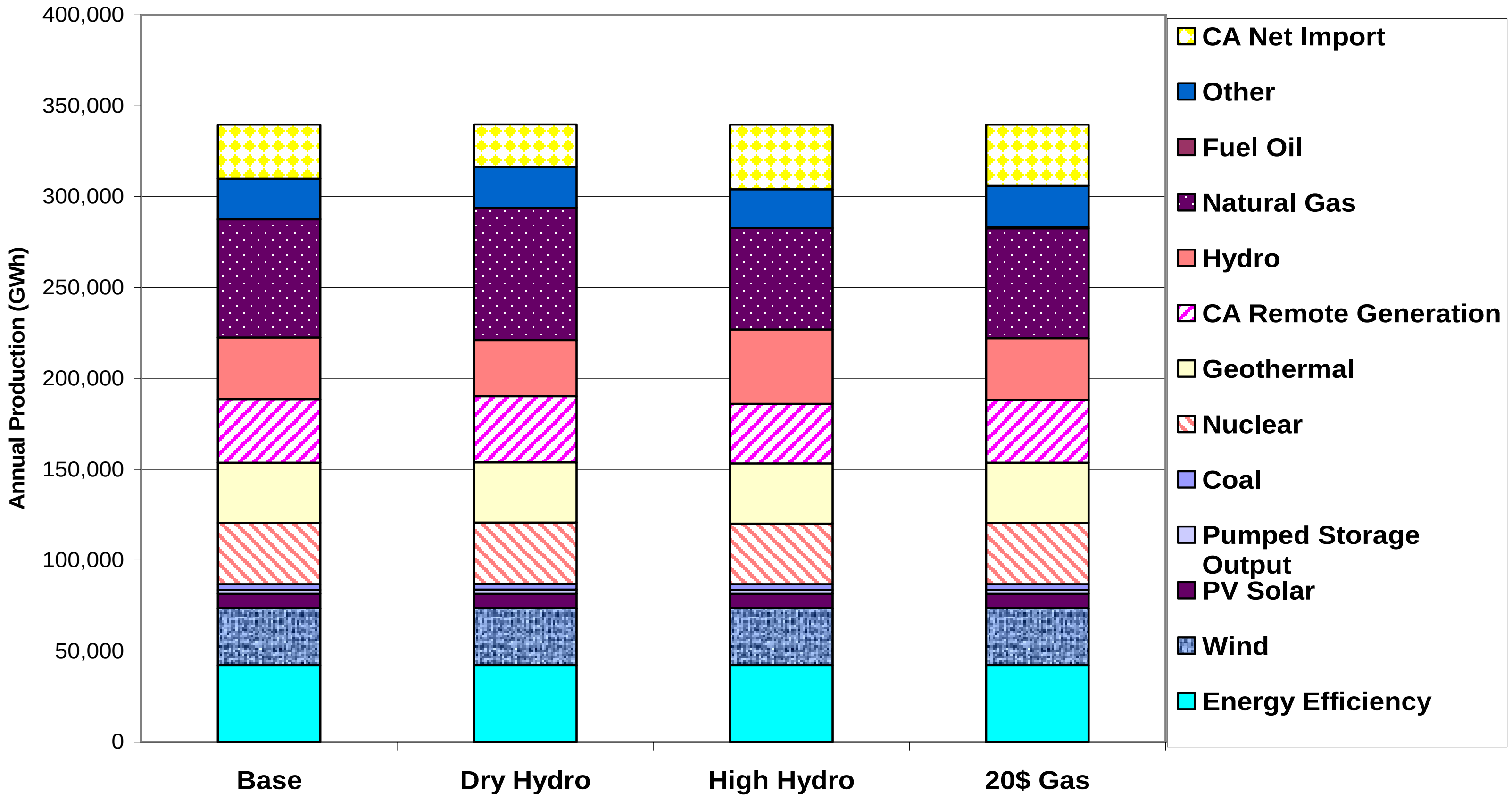


Figure 8-20: Comparison between Case 1B and Case 5A Shock Sensitivities for California System Costs in 2020 ($2006/MWh)

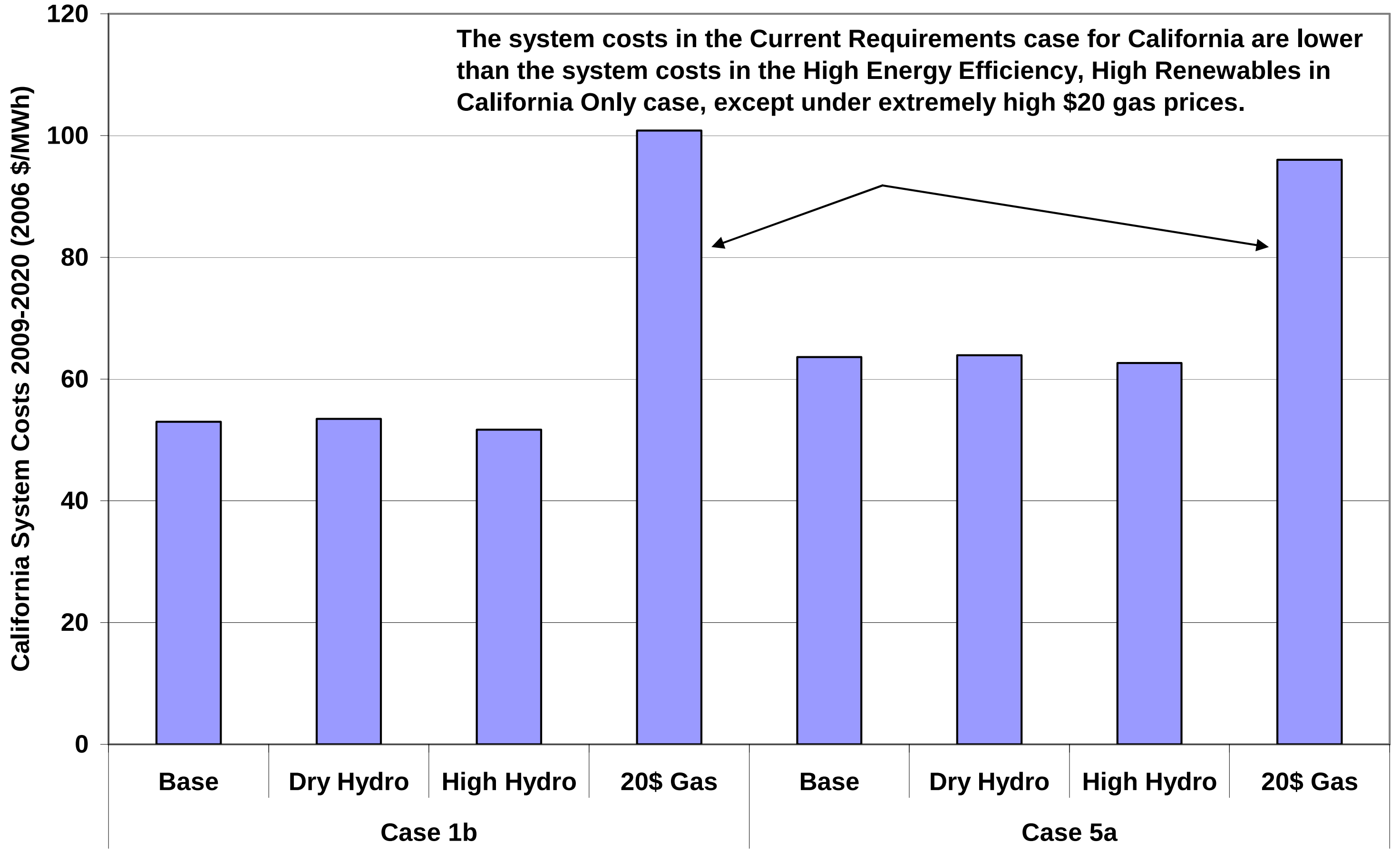
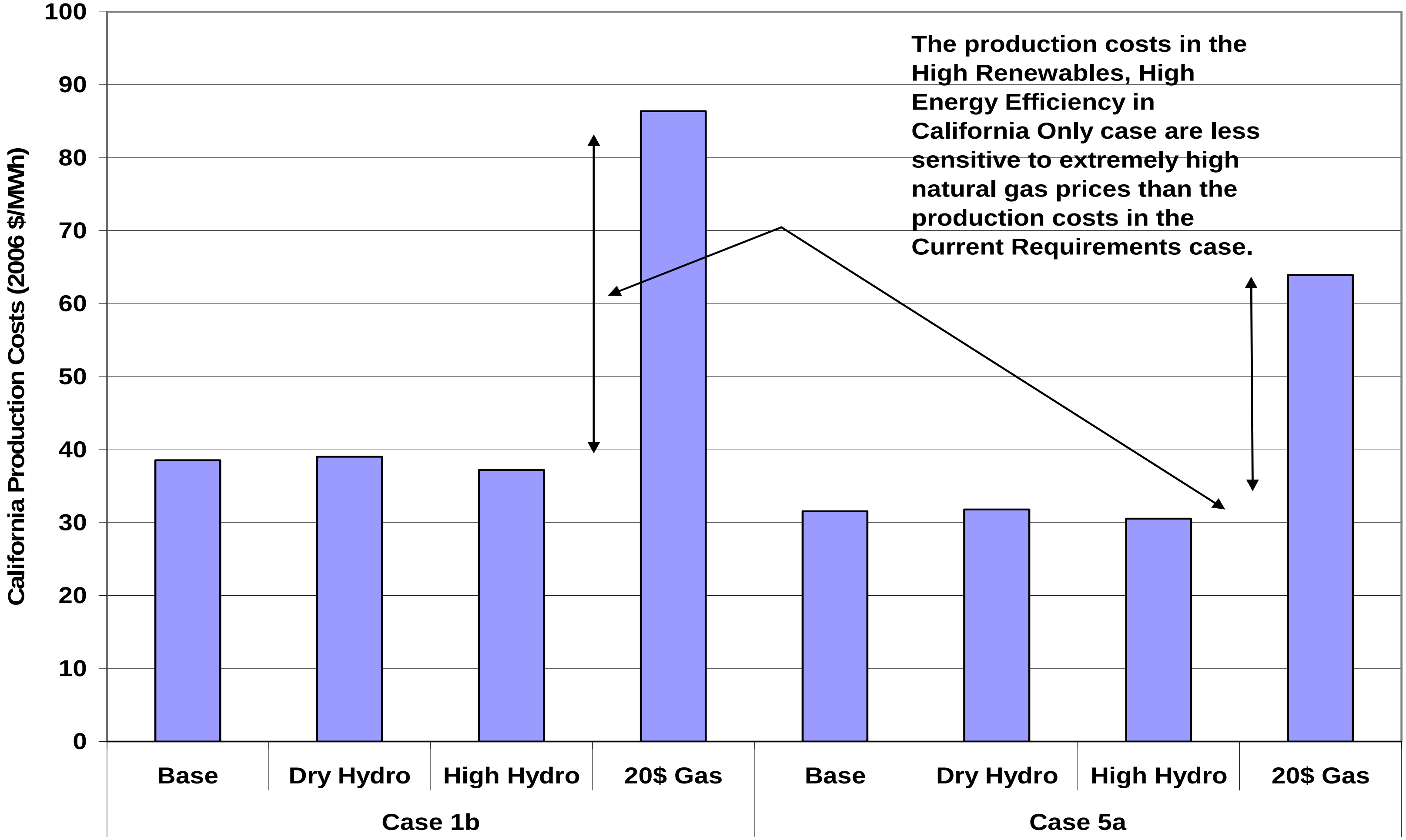


Figure 8-21: Comparison between Case 1B and Case 5A Shock Sensitivities for California Production Costs in 2020 ($2006/MWh)



8.3 Stochastic Performance

The stochastic version of PROSYM allows selected variables to be drawn from a probability distribution. A large number of alternative runs with random selection for these variables provides a probabilistic description of the results. Since this process involves extremely extensive computations, it cannot be employed for all variables or even all cases. This method was used for Case 1 and for Case 4A to compare the relative uncertainties of conventional system performance versus one emphasizing renewable resources. Resource adequacy frameworks like that designed by the CPUC have two features: (1) resources like wind and solar without backup are discounted from nameplate to "qualifying capacity" using observed on-peak performance, and (2) require the mix of resources to satisfy a 15 percent planning reserve margin over and above 1:2 peak demand. The analysis for this study illustrates the implications for system performance and reliability of the uncertainty for those variables with known probability distributions.

The analysis for this study illustrates the implications for system performance and system reliability resulting from several specific variables whose uncertainties have well known probability distributions.

8.3.1 Reliability

The stochastic analysis allowed calculation of Loss of Load Probability (LOLP) 29 for the year 2020 in Cases 1 and 4B. Case 1 reflected a resource buildout designed to achieve a 15 percent to 17 percent planning reserve margin for every control area in WECC. These control area targets were developed with the peak load for each control area. As a result, on a coincident peak basis, there is about a 28 percent planning reserve margin in the year 2020. This shift from control area peaks to a single coincident Western Interconnection peak includes several kinds of adjustments: (1) seasonal differences between the Northwest and California, specific month within season adjustments, such as PG&E peaking in July and SCE peaking in September, (3) and hour of day adjustments such as SDG&E peaking at noon while SMUD peaks at 7:00 PM. Since each control area/transarea was required to satisfy at least 15 percent PRM for its own peak, the coincidence adjustment leads to more resources that would be needed for the coincident Western Interconnect peak.

Given this large level of reserves, the stochastic analysis of WECC for the year 2020 did not turn up any single hour when there was an inability to serve load in WECC. The modeling indicates that if transmission lines are in place, problems in one sub-area of the WECC can be adequately addressed by bringing in power from other sub-areas of

[29] Loss of Load Probability (LOLP) is a metric for measuring of the reliability of an electricity system. Frequently an LOLP value of one day in 10 years is held up as a standard of reliability that electrical systems should satisfy.

WECC that are not experiencing the problems. In other words, a 15 percent to 17 percent planning reserve margin requirement for each control area would provide a very reliable power system from a generation adequacy standpoint.

A series of plants were removed to determine the capacity of resources that would have to be reduced in the year 2020 to discover when a WECC-wide Loss of Load Probability of approximately one day in 10 years might occur. This testing concluded that if 20,000 MW of generation were removed from the original Case 1 for year 2020, there would be an 18 percent margin WECC wide (on a concident peak basis), and there would be a Loss of Load Probability of approximately one day in 10 years.

Table 8-5: Resource Adjustments to Test Reliability of Case 1 for 2020

	Base Case (MW)	Reduced Gen	Difference (Base-Case1)
Load	191372	191372	0
Total	191372	191372	0
Hydro	63175	63175	0
Pumped Storage	4126	4126	0
Dependable Wind	5785	5785	0
Thermal	172245	152283	19962
Purchase	401	401	0
Total	245732	225769	19962
Margin	28.41	17.97%	

In an effort to determine whether a resource mix emphasizing renewables with considerable variability would have different results, year 2020 of Case 4B was studied. The test was conducted to compare the relative uncertainties of conventional system (e.g., gas fired peaker) performance versus one emphasizing renewable resources. Two key observations influence the results. When the renewables were added, only their dependable capacity contribution was included in the calculation to satisfy the 15 percent to 17 percent planning reserve margin. Therefore, rather than reducing gas-fired peaker MW on a one-on-one basis with wind or solar capacity, the peakers were only reduced by the wind and solar resource's dependable capacity. Second, in Case 4B, as dependable renewable capacity was added, generic peakers were removed to the point that all were eliminated. Once they were all eliminated, no further capacity was removed, and aggregate capacity increased. As such, the margin in Case 4B is higher than in Case 1 in the year 2020. With these two key observations in mind, it should be no surprise that the stochastic analysis of WECC for the year 2020 in Case 4B did not turn up any single hour when there was an inability to serve load in WECC. Since Case 1 did not show any inability to serve load, Case 4B, with its higher margin, was projected to be even more reliable. In effect, the simplified resource adequacy criteria used to construct the resource mix were sufficient to ensure that conventional reliability measures were satisfied.

8.3.2 Volatility of Cost

In addition to identifying the probability of not having sufficient generation to serve load, the stochastic analysis gives a more robust indication of the volatility of costs in Case 1 versus Case 4B. This was of interest since Case 1 emphasizes conventional generation much more susceptible to fuel costs than is Case 4B, which emphasizes renewable generation that has higher fixed costs but lower variable costs.

Table 8-6 provides the results and a comparison with the deterministic results using basecase assumptions.

Table 8-6: Comparison of Expected Range of Cost Variability from Stochastic Assessment for Year 2020

	Deterministic	Stochastic		
Alternative Case	Basecase Values	10th Percentile	Expected Value	90th Percentile
Case 1	45,074,700	40,931,681	44,327,464	48,023,428
Case 4b	47,523,895	44,426,300	46,771,217	49,397,181

Source: Global Energy

The deterministic cost of each of these cases is slightly higher than the stochastic average cost. This can be attributed to the fact that the deterministic result comes from a single pass of the hours of the year 2020 while the stochastic average values come from averaging 100 passes (using Monte Carlo draws as described above) of all the hours of the year 2020 and then averaging the 100 results.

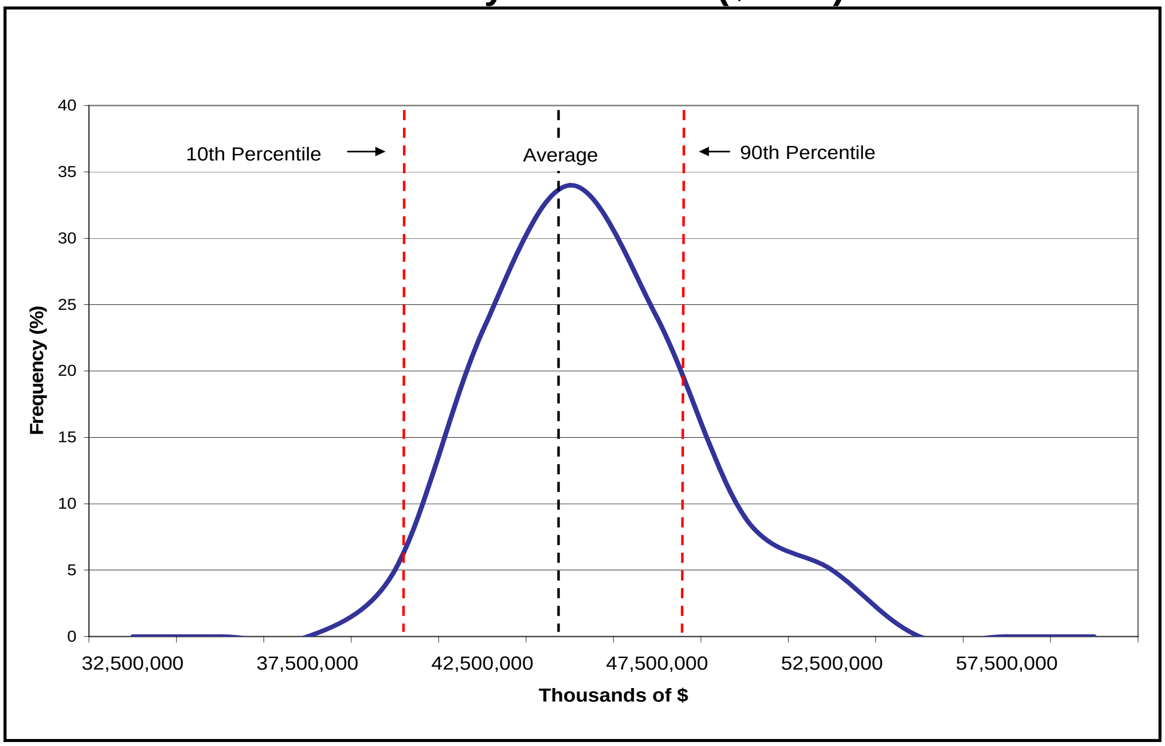
The figures below provide a different perspective on the volatility of cost as determined by this stochastic analysis. Figure 8-22 summarizes Case 1 results, while Figure 8-23 summarizes Case 4B results. These figures show the histogram of the 100 iterations of cost, the average of the 100 iterations, and the 10 percent and 90 percent confidence levels.

As intuition predicts, this study indicates that while the expected cost of Case 4B is greater than the expected cost of Case 1, the probable range of costs of Case 4B is significantly less than the probable range of costs of Case 1.[30] The shape of the

[30] Since the reserve margins for Case 4B are higher than for Case 1, it is unclear how the total cost increase noted for Case 4B might be adjusted if the reserve margins were equivalent.

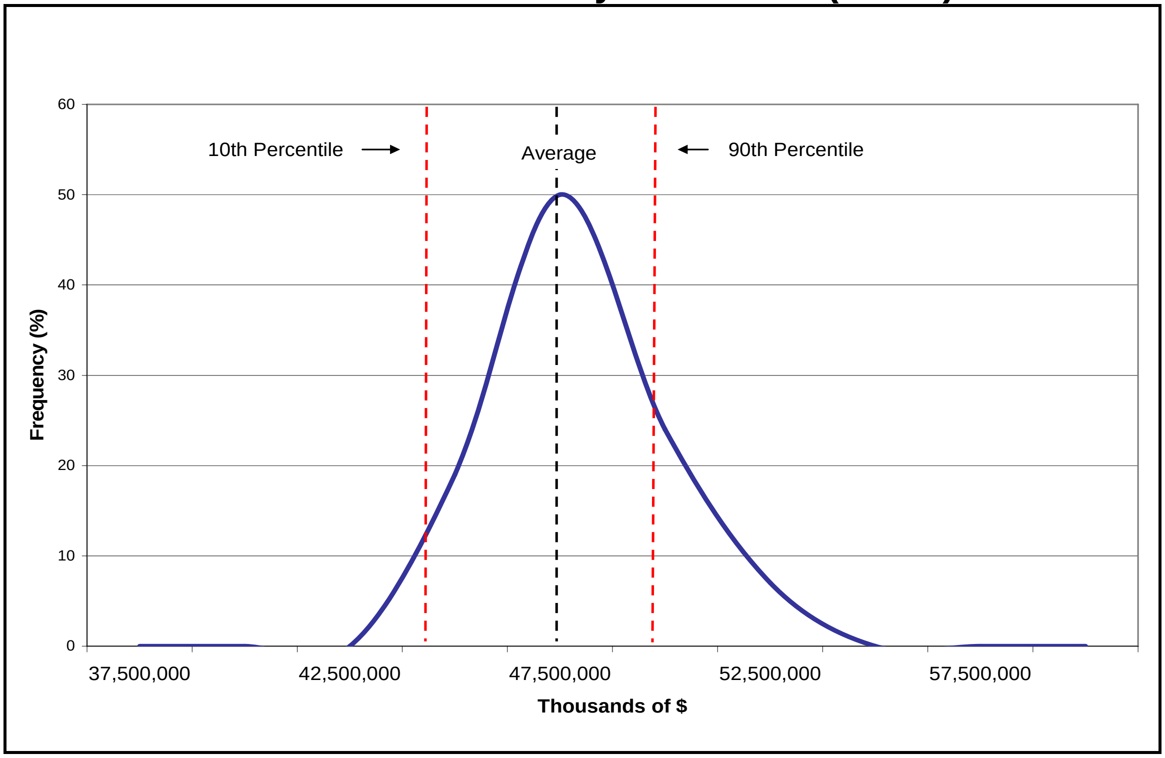
distribution is narrower for Case 4B than in Case 1. Interestingly, the maximum value for the two cases is nearly identical, while the minimum value for Case 4B is substantially higher than for Case 1. Thus the compression in the distribution comes from the lower range moving toward the higher range. Again, this might be expected since the tradeoff of fuel costs versus capital costs means that the low-end fuel costs do not provide as much of a benefit in a resource mix with lesser amounts of fossil-generated electricity.

Figure 8-22: Stochastic Analysis for Case 1 — Distribution of Total System Costs ($2006)



Source: Global Energy

Figure 8-23: Stochastic Analysis for Case 4B — Distribution of Total System Costs ($2006)



Source: Global Energy

8.4 Implications of Retiring California's Aging Power Plants

Retiring aging power plants and replacing them with units that provide the necessary services were assessed with a supplemental study first conducted by Navigant Consulting using the power flow model PSLF, and then evaluated using the Global Energy production cost model to run modified resource cases for Southern California transarea. Southern California was used as a test bed for evaluating the impacts of retirements because it has a large number of older power plants, and it has some options for replacing retired capacity with renewable capacity in northern and eastern portions of the SCE service area, provided that suitable transmission systems upgrades were implemented. Navigant assessed the degree to which the Case 1 resource plans developed by Global Energy satisfied the principal elements of local capacity requirements and identified changes that would have to be made for each of Cases 1, 1B, 3A, and 4A following the basic theme of the scenario. In effect, the Navigant work was translated into a modified production cost dataset that better reflected the 2005 IEPR policy. These results will become another case for each of these broad thematic scenarios. Details will be provided in Appendix J at a later date.

8.5 Implications of Low Demand for Natural Gas as a Power Generation Fuel for Natural Gas Market Clearing Prices

This section describes a supplemental element of analysis that seeks to determine the implications low demand for natural gas as a power generation fuel have on natural gas market clearing prices. The extent of such impacts is dependent upon a wide number of factors, many of which are uncertain or speculative. Since only those cases with major reductions in natural gas demand seem likely to induce these effects, Cases 3B and 5B were selected for analysis because they involve the greatest decline in West-wide natural gas use as a power generation fuel compared to projections based upon conventional resource plans.

8.5.1 Analytic Approach

Global Energy's natural gas modeling system was used to determine the impacts of lower predicted usage of natural gas for electric power generation (UEG) on market-clearing natural gas prices compared to a basecase. Global Energy used GPCM® to conduct this analysis. Lower UEG demand should, all else being equal, lead to lower market-clearing natural gas prices. Small reductions should lead to negligible changes in natural gas prices. Large UEG reductions could lead to noticeably lower natural gas market clearing prices. This analysis seeks to understand the magnitude of this relationship as implied by the modeling apparatus used by Global Energy and the assumptions designed for this overall project.

Initially, the work was anticipated to proceed in two phases. First, Case 3B, assuming high levels of energy efficiency throughout the West, was selected for use as a test case to devise the method and to develop some initial results. This approach, once vetted, would then be used with the results of Case 5B (both high energy efficiency and high supply-side renewable generating technologies throughout the West) to generate a second set of results.

8.5.2 Results

Global Energy eventually conducted analyses on three versions of the case combinations described earlier: (1) one for Case 3B in which electric energy efficiency programs were increased throughout the West compared to Case 1B, (2) a special case with less energy efficiency than Case 3B (high energy efficiency in just the five western states with governors that have signed the GHG emission reduction MOU), and (3) Case 5B in which high levels of energy efficiency and renewable generating technologies occur across the entire West.

[Note: the results of these analyses and a description of the methodology are not yet complete. A supplemental write-up for Section 8.5. of this report and Appendix H-5 is forthcoming.]

CHAPTER 9: LIMITATIONS OF RESULTS

9.1 Introduction

This chapter reviews the principal features of the study so that policy makers may better understand how the results should, or should not, be used to establish energy policies. This chapter reviews some of the limitations imposed by the design of the study itself, and further reviews many of the limitations resulting from data assumptions, modeling assumptions and uncertainty characterization assumptions made in this study. It is important, when performing a careful policy analysis that addresses a specific policy question that all four sources of limitation be considered by policy makers in making a decision. This chapter seeks to provide information to allow an informed judgment to be made. On the one hand, the compressed time frame of, and constrained resources available for, the study necessarily limited its overall design, its effectiveness in dealing with the potential impacts of key uncertainties, and therefore may limit the potential usefulness of its findings. It is beyond the scope of this chapter to assess how the study results might differ had these limitations been overcome. On the other hand, this study was conducted as thoroughly, or more so, than others presented in recent IEPR proceedings.

An illustration drawn from the three results chapters immediately preceding this chapter may illustrate these points. The Case 5A results indicate that significantly increasing the penetration of energy efficiency and renewable generation in California could reduce greenhouse gas (GHG) emissions by about 30 percent. Given the assumed costs of the quantities of energy efficiency and renewable generation used to construct this case, the preliminary system cost increase of this strategy is about 1 cent per kWh on a levelized basis. Some may judge this to be a reasonable tradeoff, but there are uncertainties that could move this estimate higher or lower. The cost penalty could be higher if the actual feasibility of enticing end-users to participate in a major increase in energy efficiency programs, or of being able to achieve a 400 percent increase in renewable generation capacity from current levels, in light of the shortfalls of these strategies to date, has not been evaluated. This study does not examine how energy efficiency programs could be designed to achieve much higher penetrations without increasing costs markedly, nor does it provide more than a preliminary assessment of the entire package of costs associated with large quantities of wind, rooftop solar PV and CSP resources that are not dispatchable. On the other hand, the cost penalty could be lower if technology costs decline over time. These are uncertainties that must be understood, and in some instances probably studied in depth, before any irrevocable course of action is established.

9.2 Study Design and Execution

The fundamental design of the study imposes constraints on the interpretation of the results. Four specific features of this design should be noted:

- Physical system representation,
- Conducting "what if" assessments of a limited number of scenarios,
- Conducting an electricity sector assessment in isolation from other segments of the economy that might be required to make GHG emission reductions of their own, and
- Executing the study exclusively with Energy Commission staff without the involvement of other California and WECC stakeholders.

9.2.1 The Electric System Is Represented as a Physical System

The loads and resources in all of the transareas of WECC were modeled using PROSYM based upon the physical location and interconnection of resources. The loads, resources and contracts of individual LSEs, especially California ones, cannot be identified in any detail. Transmission load flow assessments likewise occur within the models used in a physical sense and issues relative to the ownership and contractual rights associated with the transmission system were not considered. Thus, the results presented do not address how individual LSEs might constitute their preferred resource portfolio. The results also do not address issues that are caused by contractual relationships between wholesale electricity suppliers and retailers or among retailers. For example, load migration between retailers can occur and the obligations that follow that load can migrate as well, but this study is not structured to address questions associated with that migration because the migration is fundamentally a contractual issue outside of the scope of this study.

9.2.2 Limited Numbers of Scenarios

Although nine scenarios turned into more than 50 cases when sensitivities assessments are counted, there really are only three California scenarios (Case 3A, Case 4A, and Case 5A) to compare against current requirements – Case 1B. Two more efficiency cases drawn from narrower sets of efficiency measure savings potential might sharpen cost estimates and better identify cost/benefit tradeoffs. Two more renewable cases could help to tease out differences among renewable generating technologies with quite different performance characteristics and thus system integration costs. Pursuing the preferred measures in narrow "buckets" would provide a much better idea of what degree these two obvious strategies should be pursued, but that cannot be readily discerned from the limited number of scenarios assessed to date.

9.2.3 Electricity Sector Isolated from Other Sectors with GHG Reduction Goals

Analyzing the electricity sector in isolation greatly simplified the design of the study, but it avoided hard questions such as, "What are the consequences of other sectors with GHG reduction requirements using electrification as a mitigation measure?" The implications of the load increases that would result from such cross-sector mitigation strategies are extremely hard to predict. The excessive reserves noted for the preferred cases could be interpreted to mean that there would be limited consequences from load increases, but this surface conclusion may not be warranted. Since such a case was ruled out, there is no answer to the question.

9.2.4 Limited Stakeholder Participation in the Study

The extreme time constraints of the study dictated a "crash project" approach with very limited involvement of stakeholders. Many useful comments were received at the January 29, 2007 workshop held to receive comments on the study design, but most of them were not implemented due to the time constraints for the project. Further, the findings about the extreme volatility of imports into California from Rest-of-WECC as various preferred strategies are pursued in California alone or West-wide have very large consequences for the electricity sector players in Rest-of-WECC. The credibility of these findings may be compromised by the limited insight into the project that was feasible given the study design and execution parameters.

9.2.5 Consequences of Study Design

The decision to use a physical representation means that issues associated with predicting results of individual LSEs pursuing these preferred resource strategies cannot be easily discerned. The limited number of scenarios means that it is nearly impossible to determine how much more energy efficiency and/or renewables is "cost effective." Using a single load forecast as the foundation for all scenarios means it is impossible to determine how electrification strategies as a GHG compliance mechanism would affect the electricity system, especially the costs of developing and operating the system. Failure to allow for participation by stakeholders may reduce the credibility of the results, or may necessitate a second stage of the effort to incorporate guidance that might have been accepted had it been provided at an earlier stage of the project.

Even if the data, modeling, and uncertainty issues discussed below were remedied, the design of the study itself would impose constraints on how its results could be used.

9.3 Data Assumptions

The assumptions about the amount of demand and supply side resources likely to be available at a point in time and over time, in California and throughout the West, could be improved with additional time and resources. Likewise, the representation of the likely performance and cost of demand and supply side resources within California and throughout the West could also be improved. But, because most of these assumptions about the future are inherently uncertain, making such incremental “improvements” to them does not necessarily translate into making them more accurate predictions of the future or more useful for decision making. That is, improving data is helpful, but it is not a sufficient condition for producing an analysis that better informs the policy question at issue. In this situation, “improving” the assumptions would mean making their plausible range of uncertainty more explicit and then conducting additional sensitivity analyses to determine potential impacts of the range of variation. Given that so many of the assumptions ought to be treated in this way, the number of sensitivity studies required quickly becomes unwieldy thus demanding either more time and resources or analytic methods altogether different than scenario and sensitivity analyses.

9.3.1 Efficiency and Demand Response Resource Assumptions

The quantities and costs of energy efficiency resources in California for case 1B are based directly on California Public Utilities Commission (CPUC) approved programs out to 2008 and investor owned utilities (IOUs) procurement plans out to 2016. Beyond 2016, the efficiency resource assumptions are simple extrapolations. Case 3A made direct use of the Itron efficiency potential study released in 2006, and selected economic potential less the portion related to emerging technologies. Thus the primary deficits in the IOU assumptions are that it is assumed that the IOU declared plans are feasible and that the costs of energy efficiency savings growth after 2011 is constant per unit of savings. While there may be room for further improving the IOU data, the publicly owned utility (POU) data could have been improved significantly with more time and resources. The POU data for this study was created assuming that POU cost and penetration would be 75 percent of the potentials indicated by the IOU studies.

The energy efficiency assumptions outside of California are based upon the CDEAC study and its findings have not been validated beyond that study.[31] Additional time and resources could have allowed interaction with representatives of other western states and utilities to ensure that the assumptions for the respective states are consistent with the best available current information. However, this corroboration was not done and thus the energy efficiency assumptions outside of California and the results generated from these assumptions should be interpreted with caution. For example, in assuming that the western states meet the 20 percent efficiency goal, an assumption needed to be made regarding the degree to which the goal would be met through the application of existing programs. It was decided that the efficiency numbers embedded within the load forecasts was a 9 percent energy savings. In later stages of the project a credible LBNL study was found that reaches different conclusions about what is actually included in utility load forecasts. Therefore in constructing case 3B, the incremental improvement was assumed to be 11 percent, so that cumulatively case 3B would represent the 20 percent goal expressed by the western governors. However, the 9 percent assumption

[31] The CDEAC process involved many participants who are individually recognized, but it hard to judge how representative these were.

includes some programs, like building and appliance standards, that may be reflected in western utility energy and load forecasts. It is disputable whether 9 percent is really present in the underlying load forecasts, and consequently it is unclear whether the 11 percent increment in 3B is the right level of augmentation to ensure that the CDEAC 20 percent goal is achieved.

The demand response resources outside of California were not augmented for case 3B because there was no immediately available information to support the augmentation. Identifying demand response resource forecasts outside of California through extensive interaction with western states and utilities is an important area for future improvement in this study.

9.3.1.1 Critical Areas for Data Improvement

The energy efficiency and demand response data should be improved by:

- Corroborating the IOU EE and DR procurement plans with economic potential studies.
- Gathering and incorporating better data on POU energy efficiency and demand response programs in California.
- Gathering and refining better data outside of California through extensive collaboration with western states, utilities and research organizations.
- Making the plausible range of uncertainty in the above assumptions more explicit.

9.3.2 Preferred Supply-Side Renewable Resource Assumptions

The quantity and cost of renewable energy resource deployment for Case 1B is built as an augmentation to the Global Energy Current Conditions case to reflect the presumption that the existing statutory mandates in California and the West will be met, where they exist and are defined, subject to transmission and generation lead time constraints. The construction of Case 1B sought to reflect the best available information about planned Load Serving Entity (LSE) renewable energy deployment activities but extensive interaction with LSEs to ensure a careful corroboration of these augmentations with the most recent LSE renewable energy deployment plans was not possible within the time frame of this study. Case 4A further augments renewable energy resource deployment in California based upon publicly available results to date from the Intermittency Analysis Project and the Navigant PIER study in support of the implementation of the California Solar Initiative.

The case 4B assumptions relative to renewable energy deployment outside of California rely almost exclusively on the CDEAC study results. While the CDEAC study results were developed within an extensive stakeholder process, the results are not presented at a level of granularity that allows easy application within the context of a highly granular model such as PROSYM. Therefore, many assumptions were required in transforming the general CDEAC results into detailed PROSYM assumptions. For example, the

CDEAC study does not provide portfolios of renewable resources by type, by location and by projected date of operation and consequently judgment was exercised to transform the CDEAC information into PROSYM datasets.

Ideally, estimates of changes in performance assumptions over time and associated locational supply curves of renewable energy facilities by type of renewable energy source and by transarea zone would be used to create a range of plausible renewable energy deployment assumptions. Developing these performance assumptions and supply curves would involve extensive interaction with western states, utilities and organizations and would have been desirable and highly beneficial, but time and budget constraints did not allow for the interaction or for proper data validation by western entities.

9.3.2.1 Critical Areas for Data Improvement

The preferred resources data should be improved by:

- Careful corroboration of the most recent LSE renewable energy deployment plans with the assumptions for meeting the existing statutory goals.
- Gathering and refining data at a higher level of detail outside of California through extensive collaboration with western states, utilities and organizations.
- Developing a range of plausible estimates of changes in performance over time and renewable energy locational supply curves by transarea zone and renewable energy source.

9.3.3 Non-Preferred Supply Side Resource Assumptions

The energy efficiency and renewable energy deployment assumptions that were implemented starting with case 1B and carried forward and extended through all of the following cases mean there is less need for natural gas-fired and coal-fired thermal resources. The study backed out generic additions for these technologies, but eventually all such generic additions were eliminated. The reserve margins increased in the more aggressive preferred resource deployment scenarios, because named additions considered “committed” were not eliminated and existing plants were not retired early. Canceling projects under construction or retiring facilities early are ways to obtain additional reductions in fossil capacity beyond generic plant additions, and thus reducing total costs by keeping reserves closer to planning targets, but these adjustments were not examined in this study.

Estimates of changes in performance assumptions over time and associated locational supply curves of non-preferred supply side resources should also be developed, as should plausible ranges of uncertainty about them. Developing these performance assumptions and supply curves would also involve extensive interaction with western states, utilities and organizations and would have been desirable and highly beneficial, but time and budget constraints did not allow for the interaction or for proper data validation by western entities. It goes without saying that the coal industry is vitally interested in IGCC and sequestration technologies, which are highly uncertain.

9.3.3.1 Critical Areas for Data Improvement

Future efforts should include interaction with utilities and other stakeholders in California and the west to determine plausible ranges of cost and performance assumptions for fossil resources and if under construction project cancellation or early retirement of fossil resources is justified in the more aggressive preferred resource deployment scenarios.

9.3.4 Consequences of Data Assumptions Limitations

The results generated by the study should be examined in the light of extensive use of simplifying data assumptions. In particular,

- The preferred resource input assumptions for some cases are based upon the most recent LSE preferred resource procurement plans, but there was not an attempt to corroborate those plans with recent economic potential studies.
- Largely because uncertainties inherent in assumptions are not expressly included for all of the assumptions, the results generated in this study are intended to be indicative and not determinative of the potential for and cost of preferred resource policies to generate desirable GHG outcomes.
- The results generated for the western states outside of California should not be relied upon with the same level of confidence as the results generated for California.

9.4 Modeling Assumptions

The primary purpose of this effort is to estimate the potential GHG emission effects of various preferred resource portfolios. Pursuing this goal within a reasonable time frame and budget requires that many modeling assumptions be made. While modeling assumptions may be acceptable to address the goals of this study, those same assumptions may limit one from using the study to address other interesting policy questions. For example, policy questions relative to identifying the dispatchable, local resources needed for reliable system operations under a given mix of remote, preferred resources is a very interesting question, but the modeling techniques of this study do not allow that question to be addressed in a meaningful way. This section summarizes important modeling assumptions and indicates how these assumptions limit the usefulness of the study in addressing related but more specific policy questions.

9.4.1 Transarea Modeling Does Not Address Local Reliability Requirements

Although an attempt was made to ensure system reliability by imposing a simplified version of resource adequacy requirements (15 percent planning reserve margin and de-rating capability using dependable capacity procedures) in the construction of the scenario datasets, the broad nature of the transareas means that capacity to satisfy local reliability requirements cannot be identified. Especially as supply-side renewables located far from load centers become a major portion of the resource mix, it is unclear whether sufficient resources located in or near load centers have been included to assure reliable system operation under various outage contingencies. Failure to properly include such contingent resources may understate the costs and system impacts of this strategy.

9.4.2 The Resource Portfolios Do Not Completely Address the Consequences of Aging Power Plant Retirements

The assessment of aging power plant retirement and/or repowering in California has been a focus of various studies in the 2003 and 2004 IEPR documents, and an explicit policy objective in the *2005 IEPR*. The analysis undertaken in this report reflects the need to understand the interactions of retirements of some or all of this fleet and the development of preferred resources. The analyses to be reported in detail in a supplemental Appendix J do not provide sufficient detail to determine which power plants from among this fleet ought to be re-powered in place, which must be replaced in a load pocket to satisfy local capacity requirements, and which might be replaced simply by equal capacity deliverable to load. Further, the initial transmission system implications examined are not a definitive set of transmission system upgrades that may be associated with retirement of a specific aging power plant. Although analysis toward this objective was intended as part of this study, that work has not been completed and its implications are not yet included in the results that are published in this report.

9.4.3 Transmission Requirements and Costs Are Approximations

The transmission requirements vary between the cases investigated and thus the definition of transmission needs and the costs associated with those needs are relevant to this study. Pending and known transmission projects were used whenever possible but the identified needs for some cases exceeded the capabilities of these known projects. Identifying additional new projects that meet the physical needs of the system in accommodating the new resources is a speculative exercise and both the route and costs of these projects is highly uncertain. The fact that Federal Energy Regulatory Commission (FERC) Order 890 and advances in control technologies could change the available transmission capacity and line ratings in the west only adds uncertainty. The stated costs of the expansions are provided to be indicative of the expected magnitude of costs but they are approximations. Therefore, these transmission projects and the associated system cost effects are not definitive and should not be used to establish benchmarks for the costs of specific transmission project proposals. Furthermore, with the exception of the intra-zonal transmission needs of Southern California, the transmission expansions considered were limited to those that address inter-zonal congestion issues and therefore it is likely that addressing intra-zonal congestion would add additional miles of transmission and additional costs.

9.4.4 The Attribution of Carbon Emissions to California Imports Is Not Definitive

Carbon emission projections have been assessed in three component parts: (1) emissions from power plants located in California, (2) emissions from power plants located outside of California, but owned by California LSEs and expected to provide power to serve California loads, and (3) imports of market purchases ranging from spot purchases through multi-year contracts. There is considerable debate about the proper method for attributing carbon releases from this last category. This project computed the carbon emissions from imports using Rest-of-WECC averages much like the Net System Power (NSP) method. Unlike the NSP method, this project computed the carbon emissions from a category of Rest-of-WECC power plants owned and under long-term contract to California LSEs directly using their own emission rates rather than treating them as "imports." These differences, and others, exist among approaches for calculating California's aggregate carbon responsibility.

While several of these methods may be adequate to determine aggregate emissions, none of them may be appropriate to determine the carbon emissions of a specific LSE. Such a determination would require a representation of the contract positions held by the LSE so that the estimated emissions might better reflect the actual resource mix associated with the sources satisfying that LSE's customer loads. As noted in Section 9.2.1 of this chapter, the design of this study to focus on physical representation means that no LSE-specific interpretations of carbon responsibility can be inferred from the results.

9.4.5 Non-GHG Environmental Assessment Results Are Approximations

In an attempt to be inclusive of the types of criteria pollutant emissions and water consumption associated with electric power generation, estimates of NOx and SOx are provided. Water usage for power generation is still under development and will be provided as a supplement later this summer. Emission factors and water usage factors vary by generating plant and will vary for the fleet of power plants as both announced and generic additions come on line to ensure reliability. Therefore, the results reported for these variables should be considered rough approximations.

9.4.6 Electricity Demand Feedback from Resource Plan Consequences

This study ignored an important feedback loop in the real world, e.g. higher costs lead to higher rates and lower demand for electricity. Since Chapter 6 reports that the scenarios that involve high penetrations of energy efficiency and renewable generating technologies cost more, presumably these costs have to be recovered in rates and demand will be reduced somewhat. Unless the scenario was adjusted to reduce resources commensurate with demand decreases, then adjusting for demand response to higher prices alone would further increase the reserve margins reflected in the resource plans for scenarios.

9.4.7 Resource Plan Feedback from Natural Gas Price Consequences

This study also ignored a feedback loop associated with lower costs. For example, the high levels of renewable generation and energy efficiency assumed across the West in Case 5B ought to result in a reduced price of natural gas.[32] A lower natural gas prices should reduce total electric generating costs, and lead to lower prices for end-users. Even if the energy efficiency programs are mandated, one should expect the outcome to be somewhat lower savings from the programs as customers "take back" some of the savings through "rebound effects." Lower energy efficiency savings will then increase power generation fuel consumption and lead to slightly higher gas prices. After several iterations of analysis a stable result might be achieved. This feedback process is outside of the scope of this project.

9.4.8 Resource Portfolios Are Not Optimized Relative to a Specified Objective

The resource portfolios are formed based on aggregating disparate economic potential studies, load serving entity resource plans, statutory requirements and judgment. The modeling framework does not assume that new resources are selected according to an optimization process relative to a specified objective. Therefore, questions relative to the best combination of preferred resources are not addressed in this study and one should not infer from the results of the study that the portfolios presented are optimal relative to cost, reliability or environmental performance objectives. Even less ambitious goals of relative cost-effectiveness of different levels of energy efficiency or renewables cannot be addressed, since such limited numbers of scenarios were devised and assessed.

9.4.9 Consequences of Modeling Assumption Limitations

Modeling techniques and assumptions determine the range of questions that can be meaningfully addressed by a model. The assumptions identified here limit the usefulness of this modeling effort to address certain questions. For example, questions that attempt to address the following issues are not well-suited to this modeling structure:

- Whether sufficient amounts, and appropriate locations of resources, exist to satisfy local reliability requirements.
- WECC projected composition of preferred resource portfolios by transarea or in aggregate.
- The optimal composition of the preferred resource portfolio.

[32] As noted in Chapter 8, Section 8.3, the assessment of this common sense conjecture has not yet been completed.

- Resolving the aging power plant retirement/repowering policy of the 2005 IEPR with specific plant recommendations for retirement, repowering, replacement of capacity elsewhere, transmission infrastructure upgrades, or some mix of these responses.
- The total infrastructure and/or system integration costs associated with a portfolio of preferred resources.

9.5 Uncertainty Characterization Assumptions

This project allowed for some uncertainty in natural gas prices by running most scenarios with a low, base and high gas price forecast. The project also allowed for some uncertainty by using stochastic analysis to investigate the reliability consequences of preferred resource plans relative to hydrologic variability, wind variability, solar energy variability and natural gas price variability. However, there are a number of uncertainties that could fundamentally affect results that were not explicitly addressed in this study. The effects of these uncertainties on outcome metrics are complex. The magnitude of the effects and the potential for some effects to be mutually reinforcing means that these uncertainties could substantially affect the results.

9.5.1 Electricity Demand Uncertainties

The cost, reliability and environmental emissions metrics reported in this study could each be affected by variations in electricity demand. Electricity demand might depart from the forecasts used for all cases assessed in this project for a number of reasons but none of these potential sources of demand uncertainty were investigated in this study due to a lack of time and resources. Potential sources of demand uncertainty that could be addressed include:

- Variations in economic and/or demographic projections.
- Variations in energy efficiency program effectiveness.
- Variations in total electric demand in response to widespread electrification strategies.
- Changes in peak demand attributable to persistent changes in temperature and humidity levels.

9.5.2 Performance and Cost Uncertainties of Renewable Resources

The performance and cost of preferred resources were assumed to be held constant over the duration of the study. The only exception to this rule is found with solar rooftop photo-voltaic (PV) which was assumed to decrease in cost over time since this assumption is embedded within the California Solar Initiative. Listed below are two groups of factors that could either increase or decrease the cost effectiveness of renewables compared to the assumptions used in this study. None of these real world uncertainties were addressed.

Uncertainties that could **decrease** the direct and integration costs used in this study include:

- More predictable wind performance with improvements in wind forecasting accuracy, both on a short-term hour ahead basis and longer-term time scales.
- Less variability in aggregate wind performance with improved wind diversification strategies.
- Decreases in renewable energy cost with economies of scale in equipment production.
- Reductions in renewable energy cost and performance with improvements in renewable energy technologies.

Uncertainties that could **increase** the direct and integration costs used in this study include:

- Increases in renewable technology energy cost if production bottlenecks bid up prices of equipment.
- Increases in cost of renewable generation as lower quality and more remote resource areas are developed.
- Increase in portfolio integration costs as the penetration of intermittent resources requiring back-up generation and fuel supplies increase.
- Expiration/non-renewal of tax credits included in COG studies.
- Change in resource adequacy qualifying capacity protocols to further discount wind and solar without backup by focusing more narrowly on peak hour performance.

9.5.3 System Integration Costs and Performance

The cost of integrating alternative resource portfolios is dependent upon materials improvements, changes in environmental permitting laws, changes in federal transmission system regulation, wider dissemination and use of the best available digital control technologies, improvements in control technologies, and the extent to which intermittent resources have to have back-up generation and fuel supplies or require the system to increase load-following capabilities. This study explicitly derated installed wind and solar capacity by using a resource adequacy-oriented procedure to compute qualifying capacity, and also conducted a stochastic analysis of wind and solar variation from day to day, but none of the other uncertainties were addressed.

9.5.4 Environmental and Economic Regulation Uncertainties

The outcome metrics are affected by the environmental and economic regulatory environment. Obvious examples that affect outcomes include GHG market design uncertainty, FERC wholesale market regulation uncertainty, FERC and NERC transmission system regulation uncertainty, and state PUC regulatory uncertainty.

These uncertainties affect outcome metrics positively and negatively and the net effect of these is highly uncertain.

9.5.5 Consequences of Uncertainty Characterization Limitations

The operation and expansion of the electric system is dramatically affected by hydrological conditions, fuel prices, physical capital prices, technological change, state and federal regulations, and industry institutions and practices. These factors are each sources uncertainty and characterizing them within the scenario modeling framework is a significant challenge. The potential effects of some sources of uncertainty that can be probabilistically estimated were estimated through stochastic analyses. However, most other potential sources of uncertainty were not explicitly analyzed. Thus, the results presented here should be interpreted with the recognition that incorporating additional sources of uncertainty using other analytic methods could significantly change the results or provide new insights about potential surprises.

9.6 Summary

This chapter has compiled into a single place many of the project design, and data, modeling and uncertainty limitations mentioned throughout the report. Taken as a whole they suggest caution in directly attempting to use the results to establish energy policy. The study has numerous intriguing results and findings that need to be reviewed and verified by stakeholders. Assuming this review is positive, the results might provide an idea about the physical and financial consequences of large-scale pursuit of energy efficiency and renewable generation as a GHG emission reduction strategy. It is unlikely that the aggregate GHG reductions from all LSEs pursuing these same strategies with the same general emphasis would be very different than these results. It is possible that the financial consequences, in the aggregate, could be higher or lower.

Finally, a substantial number of limitations could be reduced or mitigated with additional study as discussed in Chapter 10.

CHAPTER 10: ANALYTIC EXTENSIONS THAT SHOULD BE CONSIDERED

The January 29, 2007 public workshop on scenario design and discussions with various stakeholders revealed a number of desirable project extensions, modifications, or augmentations that have merit. Most could not be accommodated within the schedule and resources of this project. During the course of preparing this study, the study team identified numerous improvements that would make the results of the study more useful. The project team believes that some of the limitations described in Chapter 9 could either be resolved or uncertainties reduced with further analysis.

Described below are various augmentations and extensions that staff believes should be considered.

10.1 Displacement of Existing Coal Plants

Although various Cases force new resource additions of the preferred resource types, there is no forced retirement of existing coal facilities. Existing (and new construction completed by 2011) coal resources are dispatched according to their costs and other considerations in merit order dispatch. Chapter 6 has identified the extent to which imports to California fluctuate from one case to another as least-cost dispatch and the relative cost of California versus Rest-of-WECC facilities satisfy California loads. While a majority of these fluctuations are natural gas-fired facilities (see Chapter 7 for an assessment supporting this finding), coal fluctuates to a very limited degree. Additional policies like carbon taxes could be investigated to determine how existing coal and other fossil generation might be used less, what resources might then run with higher capacity factors, and what such policies might cost.

10.2 Resolving End Effect Concerns

Major penetrations of various preferred technologies, and sometimes associated transmission facilities, cannot begin until well into the decade of 2010. These facilities will operate long after the final year of the current analysis, e.g., 2020. Chapter 7's evaluation of California-only or WECC-wide renewable strategy costs notes that a 2020 time horizon may provide an unfair implication of the cost increases of these technologies. These have been called "end effects." Extending the time horizon to 2030 or beyond may give a much better idea how various preferred resources can reduce GHG emissions and whether costs of implementation can be reduced by timing preferred resource additions more closely to need for new resources due to load growth or retirement of existing fossil power plants. Even though there are new uncertainties or enlarged uncertainties by extending the time horizon, the benefits may make it worthwhile.

10.3 Improving Evaluation of the Implications of Alternative Preferred Resource Type Cost and Performance Assumptions

As noted in Chapter 9, Section 9.5.2, no systematic investigation of renewable generating technology cost or performance uncertainty was performed. As a general rule, technology costs were held constant through time. Rooftop solar PV is the sole exception to this general feature of the analysis. It seems unlikely that the CSI objectives will be met unless this technology declines in cost by a very substantial amount.

At the January 29, 2007 workshop, or in follow up comments, several parties suggested at least a parametric examination of these uncertainties. Not only are there cost and performance uncertainties, it is unclear how best to describe the consequences of these uncertainties and how to portray their implications about the relative attractiveness of the preferred resource options. One obvious consequence is simply a scaling of the results were different capital costs to be assumed for new resource additions. Another possible consequence is that shifts in cost-effectiveness among competing technologies might reverse the preference between two or more such technologies. Development of Case 2 indicated that higher natural gas prices (and some escalation of coal prices as well) could alter resource preferences.

A particular limitation of the current analysis is the cost of transmission additions. The analysis conducted at this general planning level simply does not result in a sufficient detailed transmission project characterization to allow detailed cost assessment. Some improvement may be feasible, however.

Since technology costs are a key input into the overall cost assessment, a more complete evaluation of technology cost and/or performance changes through time may be important.

10.4 Improving Evaluation of the System Costs of Integrating Alternative Preferred Resource Plans

While the study attempted to capture the costs associated with new generation and transmission, more attention could be paid to the system costs associated with alternative plans. Three particular elements could be improved:

- Intra-transarea transmission infrastructure costs of integrating resources were only addressed in a limited way in this study, e.g. within the Southern California transarea. Furthermore, the potential for improvements in transmission materials, system control technologies and federal regulation of the transmission system could affect the system costs of associated with alternative plans, and these uncertainties were not addressed.

- The operating level issues associated with wind integration that were addressed in the PIER-funded IAP effort have not been addressed in this study, since those results were not readily available at the time they were needed.
- The resource additions added in 2006 or later that were common for all cases were not calculated and included in the definition of generation costs (see Chapter 3 for a review of the system cost metric).

While this does not prevent the cases from being compared one to another to determine aggregate cost differences, it does make calculating the cost implications to end-users very difficult. For example, while the levelized costs reported in Table 6-20 suggest that there is about 1 cent per kWh difference between Case 1 and Case 5A for California electricity consumers, it is unclear how to translate this into a percentage rate increase. This capital cost limitation of the study could be remedied with relatively modest change in capital cost additions for the "named" power plants, but translating to rate impacts for consumers would still be difficult since each LSE's rate structure would be affected differentially.

10.5 Examining Fossil Fuel-Fired Resource Additions

It is self-evident that avoiding fossil fueled generation is the key to reducing GHG emissions. It is also clear that reliability dictates that dispatchable power plants must be available in sufficient quantities, and in the appropriate locations, to allow system operators to maintain frequency and voltage within acceptable limits. Given existing technologies and the limited opportunity to use storage technologies this dispatch requirement will translate into fossil power plants located near load centers and other key points in the grid.

Two groups of fossil power plants received some attention in this study, but their key role suggests further study: 1) "named additions" in the pipeline to become operational out to 2010 or 2011 and 2) existing power plants that might be retired. Which of these new facilities are truly needed?

10.5.1 Evaluating the Status of "Named Additions" Assumed to Be Constructed and Operational

This project has assumed that various power plant developments are added to the resource mix during 2007 through 2011 because the projects satisfy various criteria resulting in a "committed" designation. Because the results suggest that the levels of preferred resource additions identified in Case 1 result in excess aggregate resources compared to the 15 percent planning reserve margin criteria in many years, the question arises whether the resources "in the pipeline" are really likely to be completed and become operational, or should be. Further study of the interaction between these resource additions and preferred resources would be useful to ascertain whether various regulatory approval steps might still be in front of various "named additions." To the extent that regulatory agencies are responsible for developing GHG emission reduction policies and regulations, then they should be focusing on whether these power plants really "fit" in a GHG-reduction oriented future.

10.5.2 Retirements of Existing Power Plants

The Energy Commission has long been interested in the circumstances of about 50 aging natural gas-fired power plants located largely in Southern California. These plants play an important role in system reliability apart from their general production of energy. The California ISO has been using them pursuant to reliability must run (RMR) contracts, and beginning in 2007 they continue this role under resource adequacy contracts paid for by load serving entities pursuant to locational capacity requirements. This study has begun an examination of their replacement by other resource types in conjunction with appropriate transmission system changes. Even when the work described in Sections 5.2.3 and 8.2 of this report are completed, there will be further studies of the role of these facilities that will be needed to resolve to what extent these facilities may repowered or replaced.

10.6 Alternative Methods for Computing Carbon Emissions from Imports into California

There are a variety of legitimate methods for determining the carbon emissions associated with the import of power into California. This project has used an approach similar to that used by the Energy Commission in preparing annual Net System Power (NSP) reports. Two differences from that method have been used:

- Segregating out carbon from remote power plants and computing such emissions directly using carbon emission factors for each power plant, and
- Using the NSP method for that portion of "imports" that are unspecified market purchases characterized as spot market purchases from the composite of Rest-of-WECC, rather than from two sources of such imports.

It is clear that segregating remote emissions from other "imports" and applying a plant-specific carbon emission factor is superior to treating these plants as though they were part of the pool of imports. Global Energy tested whether the two regions or one region method for computing annual average carbon emissions from unspecified market purchases makes a difference and found that the two approach were within 4 percent of the same value in year 2020.

In the CPUC proceedings examining GHG emission accounting, other methods are being examined that might address the inherently uncertain nature of unspecified market purchases resulting from least cost dispatch of a large number of power plants in the West.

Given the importance of properly assigning emissions to entities responsible for purchasing power for delivery to end-users (the load source method) and of state government laws and utility commission requirements focusing on emissions from power plants under their jurisdiction, continued development of improvements in computing carbon emissions from "imports" is an important follow up task.

10.7 Implications of Coal Emission Sequestration

While some conventional pulverized coal additions are under construction and virtually certain to be added to the system over the course of 2007 to 2011, GHG considerations focus attention on advanced coal and involve sequestration of carbon emissions. The capital and operating costs of such facilities would modify the resource mix one might like in the future, so one or more technology designs and performance characteristics ought to be considered in addition to those technologies already within this project. Section 4.1 of this report examined the cost of sequestered coal and found it to be more expensive per unit of energy than some renewable technologies, but the comparison conducted in that section of this report needs greater scrutiny given the prominent role this technology plays among coal industry advocates.

10.8 Improvements in Various Data

This project has encountered a wide range of data limitations that affect the results reported. In many cases there are likely to be additional data that can be acquired, albeit in more laborious manner than those data readily available and used herein. In other cases improved data may need to be collected directly from project proponents. Chapter 9, Section 9.3, of the report catalogues some of these data limitations and what might be done to improve upon these limitations. Future efforts would benefit from extensive stakeholder involvement in ensuring that the best data and assumptions are used and that uncertainties regarding certain data and assumptions are acknowledged and investigated.

APPENDICES

Printable appendices will be available at:
http://www.energy.ca.gov/2007_publications/CEC-200-2007-010/appendices/

A. Case Matrix Providing Broad Features of the Nine Thematic Cases

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B-1. Case 1 Resource Plan Input Assumptions

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C. California versus Rest-of-WECC Scorecard Results

C-1. California versus Rest-of-WECC Scorecards for Base, High, and Low Gas Cases

C-2. California versus Rest-of-WECC Scorecards for the Shock Sensitivities

D. Transarea Scorecard Results

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H. Natural Gas Price Assessments

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H-2. Comparison of Natural Gas Forecasts and Their Methodologies—U.S. Energy Information Administration and Global Energy Decisions—And Development of the Base Forecast for the IEPR Scenarios

H-3. The High Gas Forecast Scenario for Sustained Natural Gas Scarcity

H-4. Results and Methodology of the Stochastic Forecasts on the Base Forecast

H-5. Impacts on Natural Gas Market Prices of Low Demand for Gas as a Power Generation Fuel in the West

(This analysis will be available at a later date.)

I. Development of Power Plant Water Consumption Factors

(This analysis will be available at a later date.)

J. Assessment of Aging Power Plant Retirements in Southern California

(This analysis will be available at a later date.)